Hawaiian Electric Company, Inc. • PO Box 2750 • Honolulu, HI 96840-0001

March 4, 2010

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Manager
Regulatory Affairs

FILED
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PUBLIC UTILITIES COMMISSION

The Honorable Chairman and Members of the
Hawaii Public Utilities Commission
465 South King Street
Kekuanaoa Building, 1st Floor
Honolulu, Hawaii 96813

Dear Commissioners:

Subject: Docket No. 2008-0273 – Feed-In Tariffs Investigation
<u>Hawaiian Electric Companies' Responses to Information Requests</u>

Attached are the Hawaiian Electric Companies'[1] responses to the information requests prepared by the Commission's consultants, the National Regulatory Research Institute and the National Renewable Energy Laboratory, dated February 19, 2010.

The response to PUC-IR-304 includes voluminous documents. One paper copy of these documents is being provided to the Commission only. Electronic copies of the voluminous documents are being provided to the other parties and the Commission via compact disc or email.

Sincerely,

Attachments

cc: Distribution List

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[1] Hawaiian Electric Company, Inc., Hawaii Electric Light Company, Inc., and Maui Electric Company, Limited are collectively referred to as the "Hawaiian Electric Companies."

PUC-IR-301

Please list each of the model inputs used to calculate each of the proposed rates in the HECO Companies' proposed Tier 1 and Tier 2 Tariff and Agreement. For each input, please provide references for the source of the data. (For example, site the source of any data used for solar PV modules.) For each of the following that the HECO Companies do not include in calculations, please describe why it was not considered. Inputs should include but not be limited to the following:

(a) Capital purchase costs
(b) Land
(c) Transportation costs
(d) Installation costs (labor)
(e) Economic life
(f) Depreciation term
(g) Income tax rate and calculations
(h) Annual operating cost
(i) Weighted average cost of capital
(j) Insurance costs
(k) Salvage/cleanup costs at the end of useful life
(l) Interconnection costs (net of metering)
(m) Interconnection Requirements Study costs
(n) Meter costs
(0) Annual capacity factor
(p) Degradation factor
(q) Sales tax
(r) Property taxes
(s) Permitting costs
(t) Engineering costs (other than interconnection studies)

<u>HECO Companies Response:</u>

(a) Capital purchase costs

A detailed narrative of capital purchase cost benchmarking has been provided in the January 21, 2010 filing "HECO Comments on Alternative FiT Tariff". For PV resources, please see page 6. For On-Shore Wind resources, pleases see page 8. For In-Line Hydro resources, please see page 9. For CSP resources, please see page 10.

(b) Land

The assumptions for land costs are contained in the appendices of the "HECO Comments on Alternative FiT Tariff".

Land costs for PV systems were assumed to be roof rental costs given the size of the projects within Tiers 1 and 2. A roof rental cost assumption of $0.10/square foot/year was used. The sources of roof rental costs are discussed in more detail on page 7 of HECO's "Schedule FIT Tier 1 and Tier 2 Tariff and Agreement" filed on January 7, 2010. For actual scenario assumptions, please see the PV Tier 1 Attachment 4 at pages 37-47 and the PV Tier 2 Attachment 4 at pages 48-58.

For wind resources, land leases are typically 2-4% of annual revenue (based upon information available from the American Wind Energy AssociationAWEA). For Hawaii, the analysis assumed that land lease costs would be at the top end of that range. For actual scenario assumptions, please see the Wind Tier 1 Attachment 4 at page 112. For Wind Tier 2 resources, please see Attachment 4 at page 126.

A narrative description discussing the land cost assumptions for CSP can be found in HECO's January 7, 2010 submittal to the Commission, "HECO Companies Schedule FIT Tier 1 and Tier 2 Tariff" on page 10. The assumptions that were made include $10,000/acre per year lease for trough and dish projects. From the available project data, trough systems are assumed to require 3 acres for a 500kW system. Dish systems are assumed to require 1 acre for a 500kW system. The land cost assumptions are scaled for the size of the project with CPV systems having the same roof rental assumptions as PV. For actual scenario assumptions, please see the "HECO Comments on Alternative FiT Tariff". For CSP Tier 1 systems, please see Attachment 4 at page 8. For CSP Tier 2 systems, please see Attachment 4 at page 26.

For In-Line Hydro systems, the pricing analysis assumes a land lease between 2-4% of revenue. For the actual scenario assumptions, please see the "HECO Comments on Alternative FIT Tariff". For In-Line Hydro Tier 1 projects, please see Attachment 4 at page 85. For In-Line Hydro Tier 2 systems, please see Attachment 4 at page 98.

(c) Transportation costs

Transportation costs were assumed to be 5% of the equipment cost for all technologies. This information was drawn from the Black & Veatch IRP-3 supply-side portfolio update report (May 2005). In addition, the analysis added the 4.72% Hawaii excise tax.

(d) Installation costs (labor)

Installation costs are included in the capital costs for each technology. Please refer to the response to part a) of this information request.

(e) Economic life

The economic life or "system life" (as it is referred in the excel model) matches the debt term of the project. The economic life is therefore 20 years for all projects. The economic life assumption is included in model runs in the appendices to the January 21, 2010 filing "HECO Comments on Alternative FIT Tariff". vFor CSP Tier 1 projects, please see Attachment 4 at page 8. For CSP Tier 2 projects please see Attachment 4 at page 26. For PV Tier 1 projects, please see Attachment 4 at page 38. For PV Tier 2 projects, please see Attachment 4 at page 49. For

In-Line Hydro Tier 1 projects, please see Attachment 4 page at page 85. For In-Line Hydro Tier 2 projects, please see Attachment 4 at page 98. For On-Shore Wind Tier 1 projects, please see Attachment 4 at page 112. For On-Shore Wind Tier 2 projects, please see Attachment 4 at page 126.

(f) Depreciation term

The depreciation term is included in the model runs and is shown in the appendices to the January 21, 2010 filing "HECO Comments on Alternative FIT Tariff". 5-year MACRS depreciation was assumed for all the technologies [IRS code: 26 USC § 168(e)(3)(B)(vi)]. For CSP Tier 1 projects, please see Attachment 4 at page 8. For CSP Tier 2 projects, please see Attachment 4 at page 26. For PV Tier 1 projects, please see Attachment 4 at page 38. For PV Tier 2 projects, please see Attachment 4 at page 49. For In-Line Hydro Tier 1 projects, please see Attachment 4 at page 85. For In-Line Hydro Tier 2 projects, please see Attachment 4 at page 98. For On-Shore Wind Tier 1 projects, please see Attachment 4 at page 112. For On-Shore Wind Tier 2 projects, please see Attachment 4 at page 126.

(g) Income tax rate and calculations

The income tax rates (state and federal) are included in the model runs and are shown in the appendices to the January 21, 2010 filing "HECO Comments on Alternative FIT Tariff". For CSP Tier 1 projects, please see Attachment 4 at page 8. For CSP Tier 2 projects, please see Attachment 4 at page 26. For PV Tier 1 projects, please see Attachment 4 at page 38. For PV Tier 2 projects, please see Attachment 4 at page 49. For In-Line Hydro Tier 1 projects, please see Attachment 4 at page 85. For In-Line Hydro Tier 2 projects, please see Attachment 4 at page 98. For On-Shore Wind Tier 1 projects, please see Attachment 4 at page 112. For On-Shore Wind Tier 2 projects, please see Attachment 4 at page 126.

(h) Annual operating cost

In-Line Hydro operating costs were entered as a consolidated fixed cost of $50/kW-yr which is the middle of the range provided for in-conduit hydro systems in KEMA's 2009 Cost of Generation Study. The KEMA study found that consolidated operating costs for community wind range from $15-$45/kW-yr. The scenario analysis used the higher end of the range from $25-$45/kW-yr because of Hawaii's higher labor costs. CSP operating cost assumptions were taken from technology specific reports. The dish operating cost assumptions ($80-$100/kW-yr) came from Navigant's Arizona Solar Electric Roadmap Study. The study can be found at the following link:
(http://www.azcommerce.com/doclib/energy/az_solar_electric_roadmap_study_full_report.pdf)
The trough operating cost assumptions ($71-$76/kW-yr) came from Sopogy, one of the stakeholder parties, and the costs are similar to the range of operating costs seen in the Arizona Solar Electric Roadmap Study. CPV operating cost assumptions were entered as a consolidated fixed cost of $50/kW-yr. This assumption was drawn from a study by ORNL and increased to reflect higher Hawaii costs (www.ornl.gov/solarsummit/JXcrystals.pdf). PV operating costs were entered as a consolidated fixed cost of $22 - $28/kW/year for Tier 1 systems and $17 -

$22/kW/year for Tier 2 systems. These O&M assumptions were taken from non-public independent engineering reports and corroborated by solar industry representatives in the proceeding. The detailed inputs are outlined in the appendices to the "HECO Comments on Alternative FIT Tariff" on pages 37–58 of Attachment 4, as described more fully below.

The specific annual operating costs are included in the model runs and shown in the appendices to the January 21st filing "HECO Comments on Alternative FIT Tariff". For CSP Tier 1 projects, please see Attachment 4 at page 8. For CSP Tier 2 projects, please see Attachment 4 at page 26. For PV Tier 1 projects, please see Attachment 4 at page 38. For PV Tier 2 projects, please see Attachment 4 at page 49. For In-Line Hydro Tier 1 projects, please see Attachment 4 at page 85. For In-Line Hydro Tier 2 projects, please see Attachment 4 at page 98. For On-Shore Wind Tier 1 projects, please see Attachment 4 at page 112. For On-Shore Wind Tier 2 projects, please see Attachment 4 at page 126.

(i) Weighted average cost of capital

Debt percentage, Debt rate, and Cost of Equity are included for each technology in the model runs in the appendices to the January 21, 2010 filing "HECO Comments on Alternative FIT Tariff". For CSP Tier 1 projects, please see Attachment 4 at page 8. For CSP Tier 2 projects, please see Attachment 4 at page 26. For PV Tier 1 projects, please see Attachment 4 at page 38. For PV Tier 2 projects, please see Attachment 4 at page 49. For In-Line Hydro Tier 1 projects, please see Attachment 4 at page 85. For In-Line Hydro Tier 2 projects, please see Attachment 4 at page 98. For On-Shore Wind Tier 1 projects, please see Attachment 4 at page 112. For On-Shore Wind Tier 2 projects, please see Attachment 4 at page 126.

(j) Insurance costs

Insurance costs are included for each technology in the model runs. The insurance costs were obtained from industry quotes.

Specific assumptions for each scenario run are provided in the appendices in the January 21, 2010 filing "HECO Comments on Alternative FIT Tariff". For CSP Tier 1 projects, please see Attachment 4 at page 8. For CSP Tier 2 projects, please see Attachment 4 at page 26. For PV Tier 1 projects, please see Attachment 4 at page 38. For PV Tier 2 projects, please see Attachment 4 at page 49. For In-Line Hydro Tier 1 projects, please see Attachment 4 at page 85. For In-Line Hydro Tier 2 projects, please see Attachment 4 at page 98. For On-Shore Wind Tier 1 projects, please see Attachment 4 at page 112. For On-Shore Wind Tier 2 projects, please see Attachment 4 at page 126.

(k) Salvage/cleanup costs at the end of useful life

The model did not include salvage/cleanup costs as these values/costs are not included in typical financing and thus were not accounted for in the defined cost of technology analysis. These costs may be considered on a societal cost basis.

(l) Interconnection costs (net of metering)

No interconnection costs outside of metering costs were included since it was assumed that the typical customer would have existing service and therefore, an existing transformer would be utilized.

(m) Interconnection Requirements Study costs

It is anticipated that the typical Oahu based Tier 1 and Tier 2 projects will not require an interconnection study.

(n) Meter costs

The HECO Companies are assuming responsibility for meter costs for the Tier 1 and Tier 2 project sizes (please see Attachment 4 of the January 21, 2010 filing "HECO Comments on Alternative FIT Tariff", at page 37).

(0) Annual capacity factor

A narrative description of the capacity factor analysis is included in the January 21, 2010 filing "HECO Comments on Alternative FIT Tariff". For PV resources, please see page 6. For On-Shore Wind resources, please see page 7. For In-Line Hydro resources, please see page 9. For CSP resources, please see page 10.

(p) Degradation factor

The degradation factor assumptions are included in the January 21, 2010 filing "HECO Comments on Alternative FIT Tariff". For PV Tier 1 resources, please see Attachment 4 at page 37. For PV Tier 2 resources, please see Attachment 4 at page 48. For CSP Tier 1 resources, please see Attachment 4 at page 1. For CSP Tier 2 resources, please see Attachment 4 at page 26. On-Shore Wind and In-Line Hydro resources do not have system degradation factors. However, wind capacity factor assumptions include average system losses over the life of the project for repairs, turbulence, blade contamination, etc.

(q) Sales tax

Sales tax assumptions are outlined in the January 21, 2010 filing "HECO Comments on Alternative FIT Tariff". For CSP Tier 1 resources, please see Attachment 4 at page 8. For CSP Tier 2 resources, please see Attachment 4 at page 26. For PV Tier 1 resources, please see Attachment 4 at page 38. For PV Tier 2 resources, please see Attachment 4 at page 49. For In-Line Hydro Tier 1 resources, please see Attachment 4 at page 85. For In-Line Hydro Tier 2, please see Attachment 4 at page 98. For On-Shore Wind Tier 1 resources, please see Attachment 4 at page 112. For On-Shore Wind Tier 2 resources, please see Attachment 4 at page 126.

(r) Property taxes

Property tax assumptions are outlined in the January 21, 2010 filing "HECO Comments on Alternative FIT Tariff". For PV Tier 1 resources, please see Attachment 4 at page 37. For PV Tier 2 resources, please see Attachment 4 at page 48. For CSP Tier 1 resources, please see Attachment 4 at page 1. For CSP Tier 2 resources, please see Attachment 4 at page 26. For On-Shore Wind Tier 1 resources, please see Attachment 4 at page 108. For On-Shore Wind Tier 2 resources, please see Attachment 4 at page 122. For In-Line Hydro Tier 1 resources, please see Attachment 4 at page 81. For In-Line Hydro Tier 2 resources, please see Attachment 4 at page 93.

(s) Permitting costs

Permitting costs are included in total capital costs. Please refer to the response to part a) of this information request.

(t) Engineering costs (other than interconnection studies)

Engineering costs are included in total capital costs. Please refer to the response to part a) of this information request.

PUC-IR-302
Please provide the basis for the 9% discount rate used to calculate levelized rates in Attachment 4 of HECO's Comments on the Alternative FIT Tariff and Standard Agreement. Provide a full and detailed narrative explanation, including citations when available, supporting the used discount rate. Specifically, why should the discount rate not equal the overall rate of return?

HECO Companies Response:

The 9% discount rate is based on the weighted average cost of capital for the assumed financing costs assuming a 40% combined federal/state income tax rate:

	Proportion	Cost Pretax	Cost After tax
Debt	35%	9%	5.4%
Equity	65%	11%	11%
Weighted Average			9.0%

The discount rate in the model is used to determine the energy price. This energy price (and resulting revenue) supports both debt and equity costs incurred by the developer, not only the overall rate of return on equity.

PUC-IR-303

According to page 7 of the HECO Companies' proposed Tier 1 and Tier 2 Tariff and Agreement:

> "Hawaiian Electric Companies focused on the higher end of both size ranges (20 kW for Tier 1 and 500 kW for Tier 2) to set the tariff at a rate that will facilitate the development of projects but also take advantage of economies of scale."

(a) Describe how HECO modeled both the costs and the performance associated with these larger-scale projects.

(b) Would Tier 1 solar rates be sufficient to facilitate residential PV solar projects that are typically between 5 and 10 kW? Please provide comparative calculations for the 7-kW projects.

(c) Would Tier 2 rates facilitate commercial rooftop solar PV projects (most of which would be larger than 20 kW but smaller than 500 kW)? Please provide comparative calculations for the 100-kW projects.

(d) Explain why 500 kW is likely to be the size for most Tier 2 projects.

<u>HECO Companies Response:</u>

(a) HECO determined a range of costs and performance data for these PV projects as outlined on page 7 of "Schedule FIT Tier 1 and Tier 2 Tariff and Agreement," filed on January 7, 2010 and on pages 6 and 7 of "Comments on Alternative FIT Tariff and Standard Agreement," filed on January 21, 2010. As described on page 6 of the "Schedule FIT Tier 1 and Tier 2 Tariff and Agreement," the projects were modeled using a publicly-available Levelized Cost of Energy (LCOE) spreadsheet tool.

(b) Tier 1 rates were set to facilitate the development of projects across the range of Tier 1 project sizes (0 – 20 kW) while taking advantage of the economies of scale typically seen in projects at the larger end of the range. A 7 kW PV project could range widely in capital costs depending on roof condition, location, etc. Accordingly, HECO has presented a wide range of costs for a 20 kW project in its filing. The rate was set to encourage the efficient deployment of PV systems without being unduly burdensome to the ratepayers.

(c) Tier 2 rates were set to facilitate the development of projects across the range of Tier 2 project sizes (20 – 500 kW) while taking advantage of the economies of scale typically seen in projects at the larger end of the range. A 100 kW PV project could range widely in costs depending on roof condition, location, etc. Accordingly, HECO has presented a wide range of costs for a 500 kW project in its filing. The rate was set to encourage the efficient deployment of PV systems without being unduly burdensome to the ratepayers.

(d) There are expected to be projects across the range of Tier 2 project sizes. Smaller projects within the Tier 2 range can be efficiently deployed to accept the proposed FiT rate. Conversely, basing the rates upon typical projects at the smaller end of the range could result in unacceptable windfalls to developers of projects at the larger end of the range, at ratepayer expense, and could in fact drive developers to the larger end of the range at the expense of development of smaller projects.

PUC-IR-304
Please provide the following reports cited on page 8 of the HECO Companies' proposed Tier 1 and Tier 2 Tariff and Agreement
(a) Black & Veatch for NREL
(b) 2006 Navigant for Arizona's Solar Electric Roadmap

HECO Companies Response:

(a) See Attachment 1. In addition, the requested document can also be found at the website shown below.

NREL CSP Analysis – Black & Veatch (2006): http://www.nrel.gov/docs/fy06osti/39291.pdf

(b) See Attachment 2. In addition, the requested document can also be found at the website shown below.

The AZ Roadmap report by Navigant:
(http://www.azcommerce.com/doclib/energy/az_solar_electric_roadmap_study_full_report.pdf)

NREL National Renewable Energy Laboratory

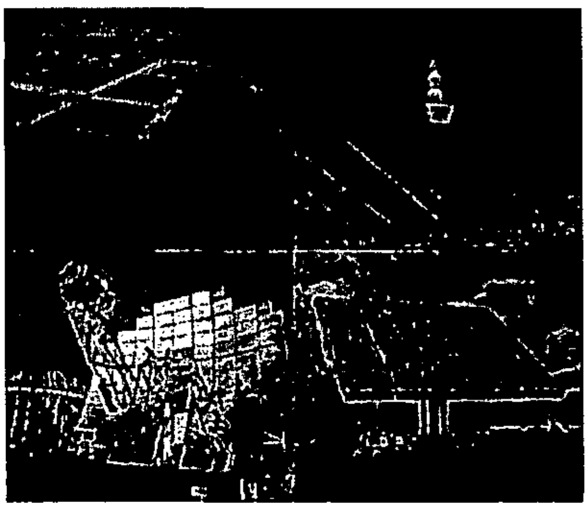
Innovation for Our Energy Future

A national laboratory of the U.S. Department of Energy
Office of Energy Efficiency & Renewable Energy

Economic, Energy, and Environmental Benefits of Concentrating Solar Power in California

Subcontract Report
NREL/SR-550-39291
April 2006

L. Stoddard, J. Abiecunas, and R. O'Connell
Black & Veatch
Overland Park, Kansas



In Collaboration with the Interfaith Environmental Council and the Coalition on the Environment and Jewish Life of Southern California
Los Angeles, California

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Economic, Energy, and Environmental Benefits of Concentrating Solar Power in California

Subcontract Report
NREL/SR-550-39291
April 2006

May 2005 – April 2006

L. Stoddard, J. Abiecunas, and R. O'Connell
Black & Veatch
Overland Park, Kansas

NREL Technical Monitor: M. Mehos
Prepared under Subcontract No. AEK-5-55036-01

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This publication received minimal editorial review at NREL

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Contents

Contents (Continued)

Tables

Figures

Figures (Continued)

Executive Summary

This study provides a summary assessment of concentrating solar power (CSP) and its potential economic return, energy supply impact, and environmental benefits for the State of California. Emphasis was placed on in-state economic impact in terms of direct and indirect employment created by the manufacture, installation, and operation of CSP plants. The environmental impact of CSP relative to natural gas fueled counterparts was studied. The value of CSP as a hedge against natural gas price increases and volatility was also analyzed.

Black & Veatch chose a 100 MW parabolic trough plant with 6 hours of storage as the representative CSP plant to focus the results of the study. Cumulative deployment scenarios of 2,100 MW and 4,000 MW between 2008 and 2020 were assumed. Based on estimates provided by the National Renewable Energy Laboratory (NREL), future CSP technology improvements were incorporated into the study by assuming that 150 MW and 200 MW plants would be constructed starting in 2011 and 2015, respectively. The NREL estimates include reduced installed costs over time as a result of technology learning and increased construction efficiency. The levelized cost of electric production was calculated for each CSP plant.

There are indications that recently bid trough plants may have somewhat lower capital costs than those used in this report; however, these data are not publicly available. Overall, while lower capital costs can somewhat lower the economic impact in California, the decrease is not expected to significantly change the conclusions of this report.

Currently (and for the foreseeable future), natural gas fueled combustion turbine based power plants are the most frequent choice for new power plants in California. As suggested in Table ES-1, the utility electric supply needs served by simple cycle and combined cycle plants tend to be those that might be served by CSP with storage. Thus, these two gas technologies are identified as conventional technology benchmarks for comparison of CSP competitiveness and economic impacts.

Table ES-1
Power Plant Characteristics

	Typical Size	Typical Duty	Capacity Factor
Simple Cycle	85 MW	Peaking	10 percent
Combined Cycle	500 MW	Intermediate	40 percent
CSP with 6 Hours Storage	100 to 200 MW	Intermediate or Peaking	40 percent

A comparison of the levelized cost of energy (LCOE) revealed that the LCOE of \$148 per MWh for the first CSP plants installed in 2009 is competitive with the simple cycle combustion turbine at an LCOE of \$168 per MWh, assuming that the temporary 30 percent Investment Tax Credit is extended. The LCOE for the CSP plant is higher than the \$104 per MWh LCOE of the combined cycle combustion turbine plant.[1]

The economic impacts of CSP construction and operation were estimated with standard economic tools. Black & Veatch used the Regional Input-Output Modeling System (RIMS II) developed and maintained by the US Bureau of Economic Analysis. This analysis revealed that each 100 MW of CSP results in 94 permanent operations and maintenance jobs compared to 56 and 13 for combined cycle and simple cycle combustion turbine plants, respectively. In terms of economic return, for each 100 MW of installed capacity, the CSP plant was estimated to create about \$628 million in impact to gross state output compared to an impact of about \$64 million for the combined cycle plant and \$47 million for the simple cycle plant. The higher CSP state economic impacts are due, in part, to the greater capital and operating costs of CSP plants. However, irrespective of plant cost, it should be noted that a greater percentage of each CSP investment dollar is returned to California in economic benefits. For each dollar spent on the installation of CSP plants, there is a total impact (direct plus indirect impacts) of about \$1.40 to gross state output for each dollar invested compared to roughly \$0.90 to \$1.00 for each dollar invested in natural gas fueled generation.

For plants installed in the latter stages of the deployment scenarios, CSP cost reductions become evident and the solar technology becomes a potentially competitive choice for both peaking and intermediate duty cycles. As shown in Table ES-2, CSP plants installed in 2015 are projected to exhibit a delivered LCOE of \$115/MWh,[2] compared with \$168/MWh for the simple cycle combustion turbine and \$104/MWh for combined cycle plants. At a natural gas price of about \$8 per MMBtu, the LCOE of CSP and the combined cycle plants at 40 percent capacity factor are equal.[3] Note that this analysis does not assume improvements to combustion turbine power generation technology, which were outside the scope of this study. However, assuming that improvements to combustion turbine power generation efficiency and cost are likely to be modest, the LCOE of CSP in 2015 is likely to be competitive with combustion turbine power generation technologies.

[1] These prices use the California Market Price Referent (MPR) gas price forecast, which is equivalent to \$6.40/MMBtu escalated at 2.5 percent annually. All dollars are \$2005.
[2] With the permanent 10 percent ITC. With the 30 percent ITC, the cost drops to \$103/MWh.
[3] The MPR gas forecast for 2015 is \$8/MMBtu. Futures prices on NYMEX were well above \$10/MMBtu for the last four months of 2005, and are down to roughly \$7.50/MMBtu as of April 1, 2006.

Table ES-2
Delivered Levelized Energy Cost and Economic Impacts for CSP and Gas Technologies in 2015 ($2005)

	Delivered Energy Cost	Permanent Jobs, per 100 MW	GSP, $million per 100 MW
Simple Cycle*	$187/MWh	13	$47
Combined Cycle*	$119/MWh	56	$64
CSP with 6 Hours Storage**	$115/MWh	94	$628

*The 2015 MPR natural gas price of $8.00 per MMBtu escalating at 2.5 percent annually was used.
**CSP assumes permanent 10 percent ITC.

CSP is a fixed cost generation resource - that is the cost of generating each MWh of electricity is primarily dependent on the capital cost of the facility, rather than on fuel costs as is the case with natural gas fueled generation. Therefore, installation of more fixed-cost generation on the California electric system could reduce the effect on electricity prices resulting from natural gas price increases and volatility. This is relevant to current generation investment decisions because of recent natural gas price volatility and price increases as shown on Figure ES-1.

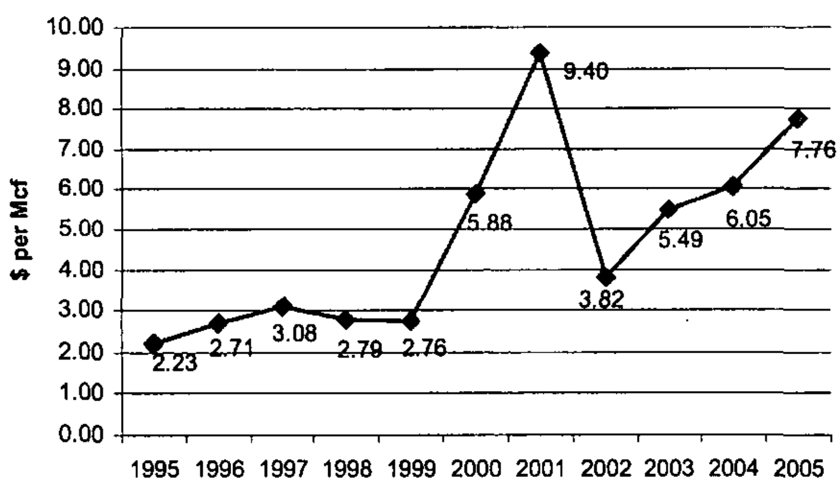


Figure ES-1
California Electric Power Sector, Annual Average Natural Gas Prices, $ per Mcf
(Source: Energy Information Administration)[4]

[4] Data for 2005 is for January through November only. Data found at www.eia.doe.gov.

Recent studies have suggested that the installation of CSP, wind or other non-gas plants in lieu of new natural gas fueled generators can relieve a portion of the demand pressure behind gas price volatility. Lawrence Livermore Laboratory and others suggest that the natural gas price could decline by one to four percent for each change of 1 percent in demand. The 4,000 MW high deployment scenario could result in a savings of $60 million per year for natural gas in California for a 1 percent price reduction for a 1 percent usage reduction. At the higher price impact range, the California savings could be four times greater.

Power generation with CSP technology does not result in any significant air emissions compared with a business as usual approach. Therefore, if the installation of CSP avoids the installation of new natural gas fueled power stations or avoids the operation of existing power stations, there would be a net reduction in air emissions in California. Using the natural gas combined cycle plant – the cleanest, most efficient fossil technology – as a proxy, data for criteria air emissions reductions were developed. For the 4,000 MW deployment scenario, at least 300 tons per year of NO_x and 7.6 million tons per year of CO_2 would be avoided. If the fossil displacement is simple cycle gas turbines or coal fired plants, these values would be larger.

Black & Veatch has made the following conclusions about the deployment of CSP from this analysis:

- California has high quality solar resources sufficient to support far more CSP than either the 2,100 MW or 4,000 MW scenarios analyzed.
- Depending on the CSP plant interconnection point and the load profile of the local electricity provider, CSP with 6 hours of storage could perform peaking and/or intermediate generation roles for a utility.
- Investment in CSP power plants delivers greater return to California in both economic activity and employment than corresponding investment in natural gas equipment:
  - Each dollar spent on CSP contributes approximately $1.40 to California's Gross State Product; each dollar spent on natural gas plants contributes about $0.90 - $1.00 to Gross State Product.
  - The 4,000 MW deployment scenario was estimated to create about 3,000 permanent jobs from the ongoing operation of the plants.
- Operations period expenditures on operations and maintenance for CSP create more permanent jobs than alternative natural gas fueled generation. For each 100 MW of generating capacity, CSP was estimated to generate 94 permanent jobs compared to 56 jobs and 13 jobs for combined cycle and simple cycle plants, respectively.

- Energy delivered from early CSP plants (startup in 2007) costs more than that delivered from natural gas combined cycle plants[5] ($157 per MWh vs. $104 per MWh, based on a 30 percent ITC for CSP). With technology advancements, improvements to CSP construction efficiency, and with higher gas prices consistent with 2015 MPR projections, CSP becomes competitive with combined cycle power generation ($115 per MWh vs. $119 per MWh, even with the permanent 10 percent ITC). Most of the economic and employment advantages are still retained.
- CSP plants are a fixed-cost generation resource and offer a physical hedge against the fluctuating cost of electricity produced with natural gas.
- Each CSP plant provides emissions reductions compared to its natural gas counterpart; the 4,000 MW scenario in this study offsets at least 300 tons per year of NO_x emissions, 180 tons of CO emissions per year, and 7,600,000 tons per year of CO_2.

The economic and employment benefits, together with delivered energy price stability and environmental advantages, suggest that the CSP solar alternative would be a beneficial addition to California's energy supply. While early CSP plants are more costly than their traditional gas counterparts, subsequent plants are estimated to become nearly cost competitive on a levelized cost of energy basis.

[5] Based on MPR gas prices for 2007, $6.40/MMBtu, and assuming a 100 MW CSP plant with 6 hours storage and a 500 MW combined cycle plant. Both CSP and combined cycle plants operate at 40 percent capacity factor. All dollars are $2005.

1.0 Introduction

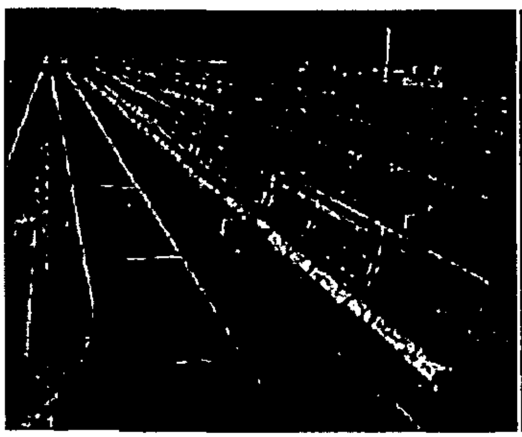
This report documents work performed by Black & Veatch Corporation (Black & Veatch) on the "Economic, Energy, and Environmental Benefits of Concentrating Solar Power in California," a study funded by the National Renewable Energy Laboratory (NREL) under subcontract AEK-5-55036-01. The objective of the study was to characterize commercial and developing CSP technologies and estimate the direct and indirect economic impacts of CSP deployment. The economic impact of CSP deployment was calculated by considering the impact to Gross State Output, earnings, employment, and to state tax receipts. The study was divided into five tasks:

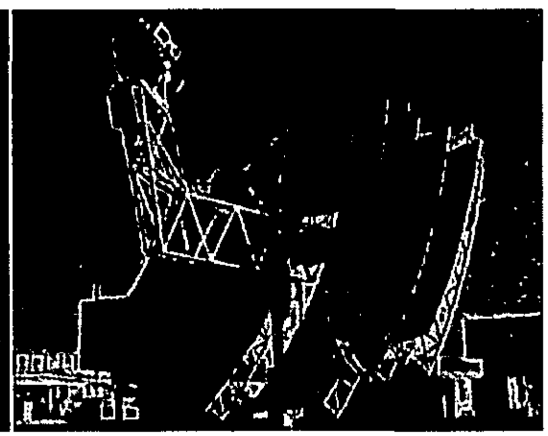
- Task 1: Technology Assessment
- Task 2: Solar Resource Assessment
- Task 3: Cost of Energy and Economic Impact Evaluation
- Task 4: Environmental and Energy Attributes and Specific Benefits to California
- Task 5: Review and Reporting

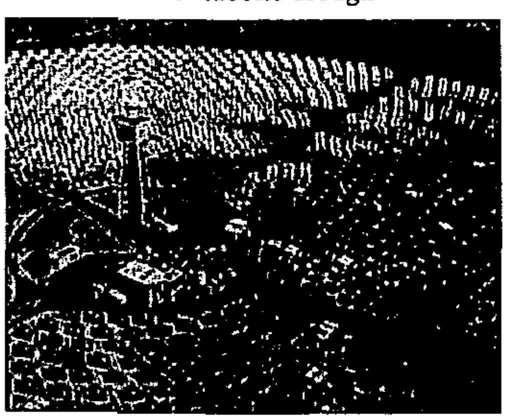
This report relies on information gathered by the Black & Veatch team which performed the "New Mexico Concentrating Solar Plant Feasibility Study," performed for the New Mexico CSP Task Force under contract to New Mexico Energy, Minerals and Natural Resources Department. The study also made extensive use of Excelergy, the NREL solar parabolic trough performance and cost modeling program. Economic impacts were calculated using the Regional Input-Output Modeling System (RIMS II model), developed and maintained by the US Bureau of Economic Analysis.

2.0 CSP Technology Assessment

Concentrating solar thermal power plants produce electric power by converting the sun's energy into high temperature heat using various mirror or lens configurations. Solar thermal systems (trough, dish-Stirling, power tower), transfer heat to a turbine or engine for power generation. Concentrating photovoltaic (CPV) plants provide power by focusing solar radiation onto a photovoltaic (PV) module, which converts the radiation directly to electricity. Figure 2-1 shows pictures of collectors for each of these technologies.


Parabolic Trough


Parabolic Dish-Engine


Power Tower

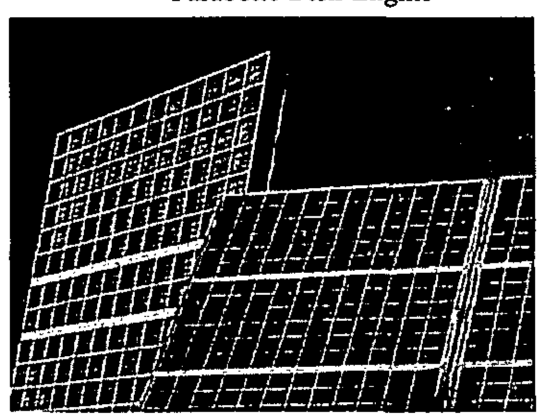

Concentrating Photovoltaic

Figure 2-1
CSP Systems
(Source: NREL)

2.1 Description of Technologies

This section provides a brief description of the four CSP technologies. A more complete description is provided in Appendix A.

Parabolic trough systems comprise rows of trough-shaped mirrors which direct solar insolation to a receiver tube along the focal axis of each trough. The focused radiation raises the temperature of heat-transfer oil, which is used to generate steam. The steam is then used to power a turbine-generator to produce electricity.

Power tower systems consist of a field of thousands of sun-tracking mirrors which direct insolation to a receiver atop a tall tower. A molten salt heat-transfer fluid is heated in the receiver and is piped to a ground based steam generator. The steam drives a steam turbine-generator to produce electricity.

Because trough and power tower systems collect heat to drive central turbine-generators, they are best suited for large-scale plants: 50 MW or larger. Trough and tower plants, with their large central turbine generators and balance of plant equipment, can take advantage of economies of scale for cost reduction, as cost per kW goes down with increased size. Additionally, these plants can make use of thermal storage or hybrid fossil systems to achieve greater operating flexibility and dispatchability. This provides the ability to produce electricity when needed by the utility system, rather than only when sufficient solar insolation is available to produce electricity, for example, during short cloudy periods or after sunset. This capability has significantly more value to the utility and potentially allows the owner of the CSP plant to receive additional credit, or payment, for the electric generating capacity of the plant.

Parabolic dish systems use a dish shaped arrangement of mirror facets to focus energy onto a receiver at the focal point of the collector. A working fluid such as hydrogen is heated in the receiver, and drives a turbine or Stirling engine. Most current dish applications use Stirling engine technology because of its high efficiency.

CPV systems use either parabolic dish mirror systems or a large array of flat Fresnel lenses to focus energy on PV cells. The PV cells generate direct current electricity, which is converted to alternating current using a solid state inverter.

Dish and CPV systems are modular in nature, with single units producing power in the range of 10 kW to 35 kW. Thus, dish and CPV systems could be used for distributed or remote generation applications, or in large arrays of several hundred or thousand units to produce power on a utility scale. Dish and CPV systems have the potential advantage of mass production of individual units, similar to the mass production of automobiles or wind turbines. At this time, neither the dish Stirling or CPV system use storage or hybrid fossil capabilities to provide a firm resource. CPV systems could, of course, make use of battery energy storage; however, present battery storage technology is comparatively inefficient and expensive.

2.2 Commercial Status of Technologies

The largest group of solar systems in the world is the Solar Energy Generating Systems (SEGS) I through IX parabolic trough plants in the Mohave Desert in southern California. The SEGS plants were built between 1985 and 1991 and have a total capacity of 354 MW. These plants have generally performed well over their 15 to 20 years of operation. There are several other commercial trough projects in the planning or active project development stage, including a 64 MW plant in Nevada and several 50 MW plants in Spain. Integrated Solar Combined Cycle Systems (ISCCS) are in various stages of planning in southern California, India, Egypt, Morocco, Mexico, and Algeria. A 1 MW trough plant was recently constructed for Arizona Public Service (APS), and is currently in startup.

There are no operating commercial dish-Stirling power plants. Recently, installation was completed on a six dish test deployment at Sandia National Laboratories (SNL) in Albuquerque. This development is under a joint agreement between Stirling Engine Systems (SES) (Phoenix) and SNL. On August 2, 2005, Southern California Edison publicly announced the completion of negotiations on a 20-year power purchase agreement with SES for between 500 to 850 MW of capacity (producing 1,182 to 2,010 GWh per year) using parabolic dish units. On September 7, 2005, SES announced a contract with San Diego Gas & Electric to provide between 300 and 900 MW of solar power using the dish technology. Pricing for these power purchase agreements remains confidential. These large deployments of dish Stirling systems are expected to drastically reduce capital and O&M costs and to result in increased system reliability.

There are no commercial power tower plants in operation. The 10 MW Solar One plant near Barstow, California, operated from 1982 to 1988 and produced over 38 GWh of electricity. Solar One generated steam directly in the receiver. To implement improved heat transfer and thermal storage, the plant was retrofitted with a receiver, storage system, and steam generator using a molten salt heat transfer fluid. The retrofitted plant, named Solar Two, operated from 1998 to 1999. In addition to Solar One and Solar Two, experimental and prototype systems have operated in Spain, France, and Israel. Abengoa in Spain has announced an 11 MW project called PS 10. ESKOM, the state-owned utility in South Africa, is considering a 100 MW molten-salt plant. A 17 MW molten salt plant in Spain, Solar Tres, was planned by Ghersa, Boeing, and Nexant. However, execution of this project appears to be unlikely at this time.

CPV systems are being offered by Amonix, Inc., a US manufacturer, and Solar Systems Pty, Ltd, an Australian firm. These systems are offered in 25-35 kW sizes. There are 547 kW of Amonix systems deployed at APS. Planned deployments in the near future include 10 to 20 MW in Spain. Ten Solar Systems dish PV systems have been deployed since 2003, for a total capacity of 220 kW, with the construction of an additional 720 kW under way. Several contracts are anticipated in the relatively near future in the US Southwest to comply with Renewable Portfolio Standard (RPS) requirements.

2.3 Technology Selection for Benefits Analysis

Black & Veatch has chosen the parabolic trough technology as the CSP proxy for economics benefits analysis because much more detailed information on construction and operation costs and performance is available for this technology than other CSP technologies. Detailed information on the amount of material and labor for plant construction and operation is needed to develop a reasonable economic impacts analysis. There are currently 354 MW of trough generation in the SEGS plants in southern California, a 64 MW plant under construction in Nevada, and several 50 MW or larger trough plants are in various stages of development around the world. Other technologies do not have significant commercial operating experience.

The use of trough as a proxy is not intended to suggest that future CSP installations will not include significant amounts of generation using other CSP technologies.

3.0 California CSP Resource Assessment

Concentrating solar systems make use of direct normal insolation (DNI), that part of the radiation which comes directly from the sun. Insolation is typically rated as a power density in units of kW/m^2, $Btu/h\text{-}ft^2$, or $MJ/h\text{-}m^2$. In this report, instantaneous DNI is provided in units of kW/m^2 and daily average DNI is provided in units of $kWh/m^2/day$.

The daily amount of DNI is seasonal, with greatest DNI on days close to the summer solstice, and least DNI on days near the winter solstice. The average annual daily DNI for high insolation (low cloud cover) areas of California ranges from 6.75 $kWh/m^2/day$ to 8.25 $kWh/m^2/day$. Annual electrical energy production from CSP plants is roughly proportional to the annual average DNI level.

Black & Veatch calculated the total land area in California with sufficient resource to support power generation on comparably flat land outside of environmentally sensitive areas by using solar insolation data provided by NREL. Figure 3-1 shows available land with high solar resource and land slope not greater than 1 percent, a preference for trough and power tower plants. The land area for each technology type, along with potential generation capacity in MW and GWh, is presented in Table 3-1. Capacity and generation were based on CSP systems without thermal storage. The table shows that with each CSP power generation technology there is the potential to generate many multiples of the current demand for electricity in California. The total generation capacity as of 2004 for the state was roughly 58,000 MW.[6]

Table 3-1
Concentrating Solar Power Technical Potential

	Solar Resource Land Area, mi^2	Capacity Potential, MW	Generation Potential, GWh
Parabolic Trough, no storage < 1 % slope	5,900	661,000	1,614,000
Parabolic Trough, six hours storage < 1 % slope	5,900	471,000	1,640,000
Power Tower, six hours storage < 1 % slope	5,900	342,000	1,233,000
Parabolic Dish, < 3 % slope	11,600	1,480,000	3,371,000
Parabolic Dish, < 5 % slope	14,400	1,837,000	4,196,000
Concentrating PV, < 3 % slope	11,600	1,235,000	2,859,000
Concentrating PV, < 5 % slope	14,400	1,534,000	3,558,000

[6] www.eia.doe.gov. This is net summer capacity.

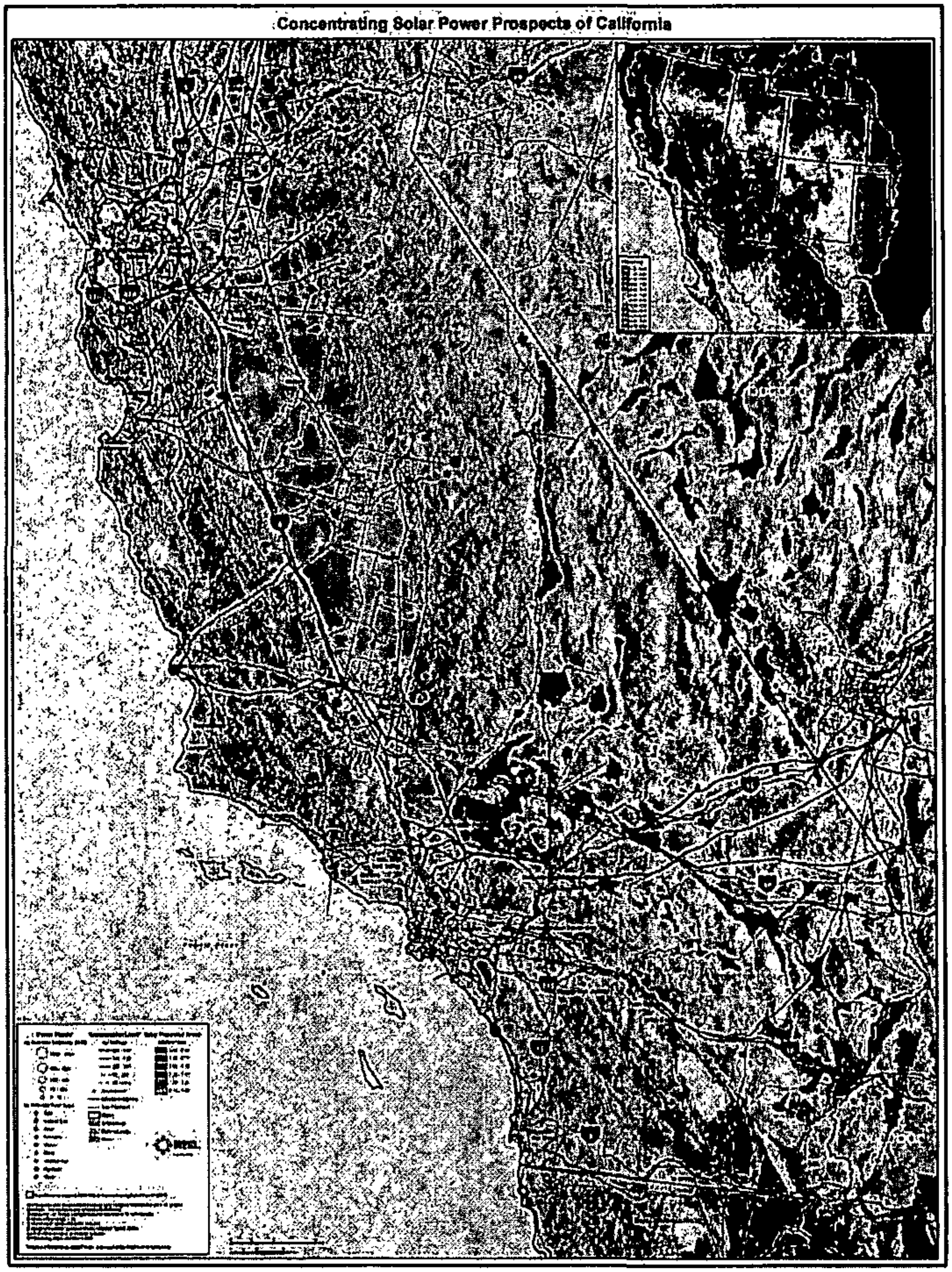


Figure 3-1
Direct Normal Radiation Solar Resource Land Greater Than 1 Percent Slope Excluded
(Source: NREL)

4.0 Deployment of CSP Plants in California

Black & Veatch developed aggressive, but reasonable, CSP deployment scenarios collaboratively with NREL to calculate the economic impact of CSP deployment (Section 5.0). By stating that the deployment scenarios are aggressive, Black & Veatch recognizes that CSP commercialization requires a long-term view that may not be supported by current economics or utility preferences. The cost of energy from the first 100 MW CSP plant may be high compared to alternative conventional (fossil fueled) or renewable energy generation options. However, CSP has the potential to be an important generation resource for California (and other southwest US states) in developing a balanced power generation portfolio.

One consideration in developing scenarios is the need for new power plants. According to the State of California "Energy Action Plan,"[7] dated May 8, 2003, California's peak electric demand was 52,863 MW on July 2, 2002. According to the Action Plan, peak demand is projected to grow at 2.4 percent annually. Platts Research Service forecasts electric demand to grow from 54,320 MW in 2005 to 77,759 MW in 2020 in the "Power Outlook Quarter 1 2005."[8] Platts also estimates that nearly 10,000 MW of generation capacity will be retired over this time frame. Therefore, Platts estimated that nearly 33,000 MW of generation capacity additions will be required to meet growing demand. The estimate for growth in energy demand is from 295,000 GWh in 2005 to 422,000 GWh in 2020, or a growth of 127,000 GWh.

Another consideration in developing scenarios is the California Renewable Portfolio Standard (RPS), which currently mandates that 20 percent of energy be generated by renewables by 2017. The California Energy Commission (CEC) has set an accelerated goal of 20 percent by 2010. Figure 4-1 shows the level of renewable energy generation in California through 2003 with projected requirements for 2010, 2017, and a more aggressive proposed goal of 33 percent by 2020. The RPS applies only to investor owned utilities (IOUs), such that only San Diego Gas & Electric, Southern California Edison, and Pacific Gas & Electric are subject to the RPS. However, municipally owned utilities such as Los Angeles Department of Water and Power and Sacramento Municipal Utility District are mandated by legislation to develop appropriate renewable plans that follow the spirit of the RPS. Therefore, renewable energy generation would need to increase to 34,200 GWh/y above the 2004 level of 28,300 GWh to achieve the 20 percent RPS by 2017.

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[7] Available from the California Energy Commission at http://www.energy.ca.gov/energy_action_plan/2003-05-08_ACTION_PLAN.PDF.
[8] Platts Power Outlook service (www.platts.com).

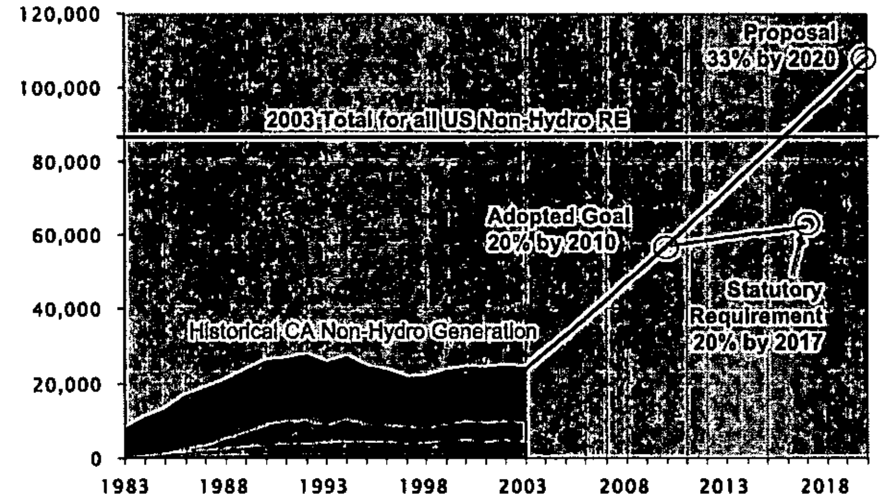

Figure 4-1
California Renewable Portfolio Standard

As discussed in Section 2.2, Black & Veatch has used trough plants with six hours of storage as the proxy for CSP generation expansion. The use of trough as a proxy is not intended to suggest that future CSP installations will not include significant amounts of generation using other technologies. The announcement of 20 year power purchase agreements between SES and Southern California Edison and San Diego Gas & Electric for a total of between 800 MW and 1,750 MW of dish engine power generation indicates strong commercial viability for dish systems.

Each 1,000 MW of parabolic trough systems, with six-hours of storage, will generate about 3,600 GWh/yr. Thus, thousands of MW of parabolic trough could, theoretically, be installed to meet state electric demand and RPS requirements. However, utilities install or purchase renewable energy on a least cost best fit (LCBF) basis. Should selected projects have energy costs which exceed the Market Price Referent (MPR), the project owner can file for payments of the energy cost exceeding the MPR from the state's New Renewable Facilities Program. Should funds not be available, the utility is relieved of its obligation to meet the RPS requirement. Additional information on the California MPR and its impact on CSP is provided in Section 6.1.

Because there is no viable approach for calculating CSP deployment on the basis of LCBF, Black & Veatch has opted to use a scenario basis for subsequent economic impact calculations. It has been assumed that the cumulative installation of CSP plants by 2020 will be between 2,100 MW and 4,000 MW (or about 8 to 18 percent of the peak demand growth). The Low and High Scenarios are summarized in Table 4-1. The Low Scenario provides a cumulative 2,100 MW of CSP addition by 2020, somewhat below

10 percent of the projected demand growth as well as about 10 percent of the IOU RPS requirement. The High Scenario provides a cumulative 4,000 MW for about 18 percent of the demand growth per Platts, and about 20 percent of the IOU RPS requirement.

Table 4-1
Deployment Scenarios

Year	Plant Size (MW)	Low Scenario			High Scenario		
		Number of Plants	Annual MW	Cumulative MW	Number of Plants	Annual MW	Cumulative MW
2008	100	1	100	100	1	100	100
2009	100	1	100	200	1	100	200
2010	100	1	100	300	1	100	300
2011	150	1	150	450	1	150	450
2012	150	1	150	600	1	150	600
2013	150	1	150	750	2	300	900
2014	150	1	150	900	2	300	1,200
2015	200	1	200	1,100	1	200	1,400
2016	200	1	200	1,300	2	400	1,800
2017	200	1	200	1,500	2	400	2,200
2018	200	1	200	1,700	3	600	2,800
2019	200	1	200	1,900	3	600	3,400
2020	200	1	200	2,100	3	600	4,000

5.0 Economic Impacts of CSP in California

Utilities are charged with planning generation portfolios which provide a safe, adequate, and reliable supply of electricity at the lowest reasonable cost and in an environmentally acceptable manner. Practically, this objective has translated into utilities selecting the lowest cost generation sources. Despite the propensity of utilities to purchase the lowest-cost resources, it has long been recognized that there can be significant socioeconomic impacts associated with new power plant investments. It follows that power plants of different types with different characteristics will have different socioeconomic impacts. The goal of this study is to estimate the impact to the regional economy of developing CSP plants in California and to compare these impacts to regional economic impacts generated by building conventional fossil fueled power stations. The direct and indirect impacts of constructing one CSP plant and a series of CSP plants over the next 15 years have been estimated.

5.1 Economic Impacts Model

The purpose of the economic impacts model is to determine the direct and indirect economic impact of developing CSP plants in California. Direct economic impacts are the dollars directly spent by the project in the region on materials, equipment, and wages. Indirect economic impacts are also referred to as the "multiplier" impacts of each dollar spent in the region. These impacts are created when a dollar is spent on goods or services produced by suppliers in the region. For example, if a dollar is spent on equipment manufactured in the region, the manufacturer spends a portion of this dollar to hire additional employees, expand production and purchase goods and services. The degree to which a dollar spent on a particular industry is re-spent in the region is the "multiplier" for that industry. The following economic metrics can be used to measure the direct and indirect economic impact of dollars spent in a given region:

- Gross State Output--The total value of goods and services produced within the state.
- Earnings--The value of wages and benefits earned by workers in the region.
- Employment--Full and part-time jobs.
- Fiscal--Impact to tax receipts by the state and local governments.

The economic impacts of a power generation project can be divided into the construction and operation periods. During the construction phase of the project, there is a direct economic impact from the portion of goods and services for the project purchased from local vendors. For example, local labor is used for construction and concrete is purchased from a local concrete plant. There are also indirect economic impacts, which include employment created by purchases from vendors and multiplier impacts in the regional economy. During the operation phase of the project, there is a direct impact from permanent jobs created by the plant and annual purchases of goods and services to support operations and maintenance of the plant. There are also multiplier impacts created by the annual plant operations and maintenance expenditures.

The model chosen for this study is the Regional Input-Output Modeling System (RIMS II model), developed and maintained by the US Bureau of Economic Analysis. This is a regional input-output (I-O) model that measures the interdependency of the various sectors of the economy through the establishment of an accounting matrix. The matrix shows the change in output, earnings, and employment in each industry due to a change in final demand (purchases from that industry). The RIMS II model is well suited for the needs of this study because it can estimate economic impacts for any county or combination of counties in the US, and includes multipliers for nearly 500 industry classifications. For this analysis, the region of study was established to be southern California, including the following counties.

- Fresno
- Imperial
- Inyo
- Kern
- Kings
- Los Angeles
- Mono
- Orange
- Riverside
- San Bernardino
- San Diego
- San Luis Obispo
- Santa Barbara
- Tulare
- Ventura

The economic analysis was limited to counties in southern California because the solar resource suitable for CSP is primarily available in southern California; thus, it has been assumed that the economic impact of CSP development would be concentrated in southern California.

The multiplier analysis included the evaluation of impacts arising from the construction and operation periods. The results for each period were then summed to arrive at the total impact for developing one and multiple CSP plants. For the construction and operation periods, the cost estimates were broken into major equipment and labor categories (e.g., solar field mirrors, construction labor, etc.). The percent of labor and capital expenditures in each category that would occur in southern California were then estimated. The following section contains a complete discussion of the technical inputs to the economic model.

The expenditures in southern California were then multiplied by the final demand multipliers for the respective industries for each major capital and labor expense. This impact estimate was then added to the initial change due to the investment. Gross State Output, earnings and output estimates were then deflated to 1997, the basis for the I-O tables in the RIMS II model. Final results were then escalated to 2005 dollars. All estimates during construction were performed on a per MW basis. A similar process was followed for the operation period, based on the annual expenditures made per CSP plant per year. This estimate included expenditures for plant staff, consumables and supplies, land rent, and other cost items. Economic impact estimates for the operation period are provided on per MW and per MWh basis.

The economic impacts of CSP deployment were then compared with the economic activity generated by 500 MW combined cycle and 85 MW simple cycle combustion turbine plants. These plants provide similar electric services to what a CSP plant provides and offer a basis for estimating the relative impacts of this renewable technology. Sizing of the combined cycle and simple cycle plants are typical sizes for plants built for intermediate and peaking service.

5.2 Input Data for the Model

An important element of the economic impact analysis is the estimation of capital and annual operations and maintenance (O&M) costs. The magnitude of the capital and annual expenditures directly impacts the magnitude of the direct and indirect economic impacts. Black & Veatch used data from the Excelergy Model, developed and maintained by NREL.[9] Capital and O&M costs were generated for parabolic trough systems with six hours of storage for a 100 MW plant built in 2007, a 100 MW plant built in 2009, a 150 MW plant built in 2011, and a 200 MW plant built in 2015.

There are indications that recently bid trough plants may have somewhat lower capital costs than those generated by Excelergy; howerver, these data are not publicly available. Overall, while lower capital costs can somewhat lower the economic impact in California, the decrease is not expected to significantly change the conclusions of this report.

[9] Excelergy is an Excel spreadsheet-based model for solar parabolic trough systems. Developed by NREL, it models annual plant performance and estimates capital and O&M costs. It uses a time step approach with hourly or finer time increment solar and weather data. Excelergy has been benchmarked against the SEGS plants.

The Excelergy-generated capital cost estimates are based on data from the SEGS plants, vendor inquiries, and various studies. NREL has developed "Learning Curves" to describe the reduction in capital and operating costs observed as more CSP plants are deployed. The learning curve cost reductions relate to technology advances, scale up, effects of mass production resulting from large scale deployment, and improvements in construction efficiency.

Table 5-1 is a summary of capital costs for the four CSP plants. Black & Veatch worked from a more detailed cost breakdown to place equipment costs into "Manufactured in southern California" and "Not Manufactured in southern California" categories. Table 5-2 is a summary of annual O&M costs for the four CSP plants.

Black & Veatch also estimated the direct and indirect economic impact of constructing and operating combined cycle and simple cycle combustion turbine plants. Because these plants provide intermediate and peaking electric services similar to those of a CSP plant, they offer a good benchmark to the economic impacts created by CSP. Table 5-3 provides the input assumptions for the combined cycle and simple cycle combustion turbine plants. Capital and operating cost breakdowns were also developed for both plant types based on Black & Veatch experience with each of these plant types to estimate the direct and indirect economic impact of constructing each plant in southern California.

Table 5-4 provides a summary capital cost breakdown and Table 5-5 provides an O&M cost breakdown for the combined cycle and simple cycle combustion turbine power plants, respectively. Black & Veatch worked from a more detailed cost breakdown to place equipment costs into "Manufactured in southern California" and "Not Manufactured in southern California" categories.

5.2.1 Estimation of California-Supplied Goods and Services

The RIMS II model calculates the economic impact of expenditures *inside of a given region*; therefore, the part of capital and operating costs spent in and out of southern California must be determined. Black & Veatch first divided the total capital and operating cost estimates into material and labor components. It has been assumed that all construction and operations labor jobs created are in southern California.

The plant cost estimates were examined on a line by line basis and percentages were applied, based on engineering judgment and knowledge of suppliers, as to what portion of the equipment purchased for the plant would be manufactured in southern California. Some of the material and equipment is available from southern California manufacturers, while other specialized items are not. Table 5-6 shows the base case assumptions used regarding equipment purchases in California. Section 5.4 provides a sensitivity analysis with lower and higher in-state spending assumptions.

Table 5-1
CSP Plant Capital Cost Breakdowns, 2005 $1,000

	2007 100 MW*	2009 100 MW*	2011 150 MW*	2015 200 MW*
Site Work and Infrastructure	2,455	2,433	2,566	2,681
Solar Field	230,865	205,109	243,059	268,441
HTF System	10,009	9,895	11,896	13,542
Thermal Energy Storage	57,957	57,937	71,320	89,390
Power Block	38,754	38,754	48,899	56,818
Balance of Plant	22,533	22,533	28,432	33,036
Contingency	30,707	28,116	33,742	37,720
Total Direct Costs	**393,280**	**364,776**	**439,915**	**501,627**
Indirects	101,106	92,814	113,469	129,746
Total Installed Cost	**494,386**	**457,590**	**553,384**	**631,373**

Source: NREL Excelergy Model.

*With 6 hours storage.

Table 5-2
Annual CSP O&M Cost Breakdowns, 2005 $1,000

	2007 100 MW	2009 100 MW	2011 150 MW	2015 200 MW
Labor				
Administration	528	528	554	554
Operations	979	973	1,088	1,158
Maintenance	633	633	664	664
Total Labor	**3,018**	**2,984**	**3,517**	**3,926**
Miscellaneous	419	415	516	599
Service Contracts	263	259	352	435
Water Treatment	260	265	413	556
Spares and Equipment	669	651	870	1,040
Solar Field Parts and Materials	1,859	1,311	1,457	1,904
Annual Capital Equipment	226	218	320	418
Subtotal	**3,695**	**3,119**	**3,928**	**4,953**
Total	**6,713**	**6,104**	**7,445**	**8,879**

Source: NREL Excelergy Model.

Table 5-3
Combined Cycle and Simple Cycle Plant Assumptions*

	Combined Cycle	Simple Cycle
Combustion Turbine Technology	2x1 7FA	7EA
Net Capacity, MW	500	85
Net Plant Heat Rate, Btu/kWh	7,000	9,700
Capacity Factor, percent	40	10
Capital Cost, $/kW	650	500
Annual O&M Cost (non-fuel), $	10,705,500	463,500
Annual Fuel Cost**	78,489,600	4,622,477

*All costs in 2005 dollars.
**Assumes a fuel cost of $6.40/MMBtu, escalated at 2.5 percent. This is equivalent to the California 2005 Market Price Referent (MPR) natural gas forecast.

Table 5-4
Conventional Combustion Turbine Power
Generation Capital Cost Breakdowns, 2005 $1,000

	2x1 7FA	7EA
Combustion Turbines & Auxiliaries	79,000	22,950
Heat Recovery Steam Generators	26,000	N/A
Steam Turbine Generator & Auxiliaries	36,740	N/A
Balance of Plant	80,150	8,653
Other Costs	86,982	8,082
Contingency	16,120	2,795
Total	**324,992**	**42,480**

Source: Black & Veatch.

Table 5-5
Conventional Combustion Turbine Power
Generation O&M Cost Breakdowns, 2005 $1,000

	2x1 7FA	7EA
Staff	2,205	179
Training & Communications	945	77
Water	1,511	42
Major Maintenance	5,289	146
Other VOM/parts	756	21
Natural Gas	103,478	3,250
Total	**114,183**	**3,714**

Source: Black & Veatch.

Table 5-6
Base Case Breakdown of Expenditures in Southern California, percent

Plant System	All Plants		2009 Plant			2011 Plant			2015 Plant			Comments
	Percent Labor	Percent Material	Percent of Total Project Cost	Percent Labor in CA	Percent Material in CA	Percent of Total Project Cost	Percent Labor in CA	Percent Material in CA	Percent of Total Project Cost	Percent Labor in CA	Percent Material in CA	
Sitework and Infrastructure	100%	0%	0.4%	100%	0%	0.3%	100%	0%	0.3%	100%	0%	All construction labor has been assumed to be in California.
Contractor Overhead	0%	100%	8.3%	0%	100%	8.1%	0%	100%	7.4%	0%	100%	The construction contractor is assumed to be located in California.
Heat Collection Elements	0%	100%	11.0%	0%	0%	10.9%	0%	50%	9.9%	0%	75%	For early plants (2009), mirrors and heat conversion elements (HCE's) were assumed to be manufactured outside southern California. At present, the major supplier for mirrors would be in Germany, while HCE's are currently produced in Israel and Germany. For plants coming on-line in 2011, 50 percent of mirrors and HCE's are assumed to be manufactured in California. For plants starting in 2015, 75 percent of mirrors and HCE's are assumed to be manufactured in southern California. The German and Israeli manufacturers currently do not have large scale production facilities for CSP equipment due to limited demand. If a large number of CSP plants were planned (and orders had been placed), one or more manufacturers would likely be induced to open manufacturing facilities in the region.
Mirrors	0%	100%	11.8%	0%	0%	11.7%	0%	50%	10.7%	0%	75%	
Metal Support Structure	0%	100%	11.5%	0%	50%	11.3%	0%	50%	10.1%	0%	50%	Steel for metal support structures is produced both inside and outside of California. We have assumed that an average of 50 percent of the material would be procured from California sources.
Misc. Solar Field Equipment	51%	49%	12.5%	91%	59%	12.2%	91%	59%	10.9%	90%	59%	Miscellaneous solar field balance of plant equipment (small pumps and motors, bolts, small bore piping, etc.) is manufactured both inside and outside of California. The assumption is based on procurement of a mix of equipment from in-state and out of state suppliers.
HTF System	7%	93%	2.3%	100%	34%	2.3%	100%	34%	2.2%	100%	34%	The balance of plant equipment for the HTP system is assumed to be procured from manufacturers located inside and outside of California. Specialized heat exchangers are assumed to be manufactured outside of California. Field erection labor is assumed to be from California suppliers.
Thermal Energy Storage	0%	100%	7.8%	0%	42%	9.2%	0%	75%	9.4%	0%	75%	We have assumed that a significant portion of steel tank fabrication will occur in California, but that specialized heat exchangers will be manufactured outside California. .
Thermal Energy Storage Fluid	0%	100%	6.7%	0%	50%	5.6%	0%	50%	5.8%	0%	50%	The heat transfer and thermal storage fluids, whether a silicone oil or a molten salt, are assumed to be specialized products produced primarily outside of southern California

PUC-IR-304
DOCKET NO. 2008-0273
ATTACHMENT 1
PAGE 29 OF 69

Table 5-6 (Continued)
Base Case Breakdown of Expenditures in Southern California, percent

	All Plants		2009 Plant			2011 Plant			2015 Plant			
Plant System	Percent Labor	Percent Material	Percent of Total Project Cost	Percent Labor in CA	Percent Material in CA	Percent of Total Project Cost	Percent Labor in CA	Percent Material in CA	Percent of Total Project Cost	Percent Labor in CA	Percent Material in CA	Comments
Power Block	23%	77%	8.4%	100%	12%	8.7%	100%	12%	8.3%	100%	12%	Steam turbines are manufactured outside of California. A portion of the auxiliaries (small motors and pumps, small bore piping, etc.) could be purchased in California.
Balance of Plant	44%	56%	4.3%	100%	50%	4.5%	100%	50%	4.3%	100%	50%	Balance of plant equipment (miscellaneous motors, pumps, electrical equipment, etc.) is manufactured in and out of California. Equipment purchased will likely be a combination of both.
Contingency	18%	82%	6.3%	95%	23%	6.2%	95%	45%	5.7%	95%	56%	The contingency could be used to cover unforeseen engineering costs, material costs, additional construction management, additional construction labor, or any other costs overruns; therefore, the portion of expenditures in-state reflect the overall project distribution.
Engineering, Const. Mgmt	0%	100%	6.6%	0%	50%	6.6%	0%	50%	6.2%	0%	50%	It is assumed that all construction management expenses will be in-state. Major engineering firms likely to engineer, procure, and construct CSP plants are located inside and outside of California. Therefore, the percentage of expenditure in California reflects the uncertainty in the location of the engineering firm selected for each project.
EPC Markup	0%	100%	6.3%	0%	30%	6.4%	0%	30%	5.9%	0%	30%	
Land	0%	100%	0.4%	0%	100%	0.4%	0%	100%	0.5%	0%	100%	
Owners	30%	50%	2.7%	50%	50%	2.7%	50%	50%	2.9%	50%	50%	Owner's costs including financing, project management, permitting/licensing, legal fees, etc., may be procured from in-state or out of state service providers; therefore, we have assumed that 50 percent of expenses could be procured from in-state sources.

Source: Black & Veatch.

In general, goods and services purchases for O&M are assumed to be from in-state sources. It was assumed that all miscellaneous costs and service contracts were southern California based. Water costs are split nearly evenly between raw water costs and chemicals. Black & Veatch has assumed 100 percent of the raw water costs are spent in southern California, while 50 percent of the chemicals are produced in California. Spares and equipment, solar field parts, and capital equipment costs were assumed to be 50 percent southern California based.

5.2.2 Costs Versus Deployment Year

To simplify the economic impacts analysis, Black & Veatch grouped the deployment scenarios into four "buckets," which contain the following years:

- 2008, 2009, 2010.
- 2011, 2012, 2013.
- 2014, 2015, and 2016.
- 2017, 2018, and 2019.

Black & Veatch used this approach because any difference in plant costs between years due to inflation is not within the accuracy of the cost estimates. Therefore, any gains in granularity in study results are not significant because of the confidence in the cost estimates.

5.3 Base Case Economic Impacts Analysis Results

Black & Veatch estimated the direct and indirect impact of the development of the reference parabolic trough CSP plant, described in Section 2.1, in southern California with an on-line date in 2008. This section provides the base case analysis. A sensitivity analysis is discussed in Section 5.4. Table 5-7 shows that constructing one 100 MW CSP plant has a direct impact to Gross State Output of over $150 million and an indirect impact of over $470 million. The table also shows that about 455 job-years of direct employment are created during the construction of the facility, which equates to over $51 million in direct earnings. The table also shows that the plant results in about 38 permanent jobs directly created by the operation of the plant; another 56 jobs are indirectly created by the operation of the plant.

Table 5-8 shows the total (direct plus indirect) economic impact per 100 MW of CSP, combined cycle and simple cycle combustion turbine plants. Table 5-8 shows that the total construction impact of CSP on gross state output at about $626 million per 100 MW is significantly larger than that for combined cycle or simple cycle combustion turbine plants at about $64 million per 100 MW and $47 million per 100 MW, respectively. The primary reason for this is the much larger total installed cost of the CSP plant, which is estimated to be $4,600 per kW in 2008 compared to the combined cycle plant at $650 per kW and the simple cycle plant at $500 per kW. However, the CSP plant has an impact to gross state output of $1.4 per $1 spent on the CSP plant, while the ratios for the combined cycle and simple cycle combustion turbine plants are in the range of $0.90 to $1.00 per $1 spent on the fossil fueled plants.

Table 5-7
Base Case Direct and Indirect Economic Impacts
of One 100 MW CSP Plant in 2008 ($2005)

	Direct Impact	Indirect Impact
Construction		
Gross State Output, $1,000/plant	151,000	475,000
Earnings, $1,000/plant	51,000	144,000
Employment, job-years	455	3,500
Operation		
Gross State Output, $1,000/year	2,400	10,400
Earnings, $1,000/year	3,140	2,540
Employment, jobs	38	56

Table 5-8 also shows the impact per GWh of power generation for the CSP and conventional technologies. This analysis revealed that CSP plant produces higher economic benefits per unit of energy produced than either of the conventional technologies. The economic impact per unit is similar between the combined cycle and simple cycle plants because of the low capacity factor for the simple cycle plant, which inflates the economic impacts per unit of energy produced.

Figure 5-1 shows the direct and indirect employment impact of the CSP, combined cycle, and simple cycle plants per 100 MW. The CSP plant also has a much larger impact on employment at about 4,000 job-years per 100 MW versus about 500 for the combined cycle plant and 330 for the simple cycle plant. This is a result of the higher capital cost and construction requirements of the CSP plant.

Figure 5-1 also shows that the CSP plant generates significantly greater economic impacts during the operation of the project. There are 94 direct and indirect permanent jobs created by the continued operation of the CSP plant, which compares to 56 jobs per 100 MW created by the combined cycle plant and 13 jobs per 100 MW created by the simple cycle plant. Again, this is the result of more labor intensive operational requirements of the CSP plant.

Table 5-8
Total Economic Impacts of One CSP or Conventional Plant in 2008 per 100 MW ($2005)

	Base Case Parabolic Trough	Combined Cycle Combustion Turbine	Simple Cycle Combustion Turbine
Construction			
Gross State Output, $1,000	628,000	64,000	47,000
Earnings, $1,000	196,000	23,500	17,700
Employment, job-years	3,990	448	327
Operation			
Gross State Output, $1,000/year	12,800	10,000	2,000
Earnings, $1,000/year	5,680	2,700	700
Employment, jobs	94	56	13
Operation			
Gross State Output, $1,000/GWh	36	24	23
Earnings, $1,000/GWh	16	6	8
Employment, jobs/GWh	0.26	0.16	0.15

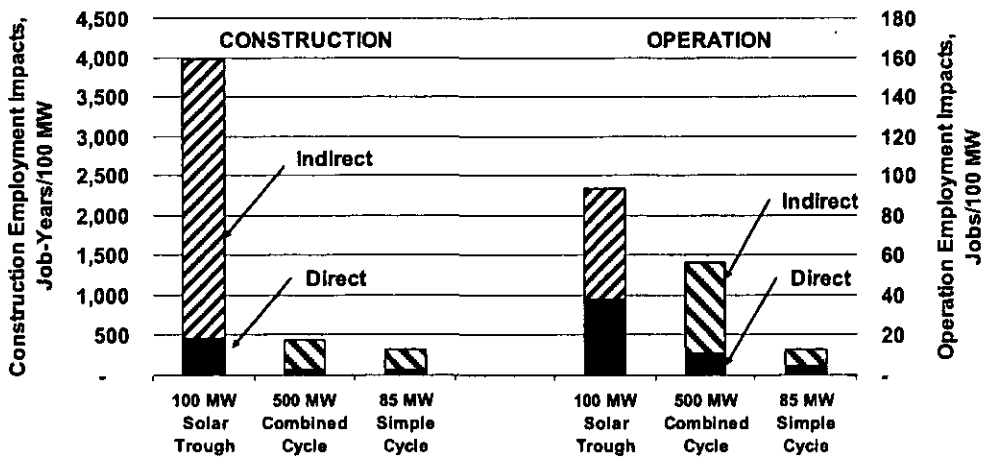

Figure 5-1
Base Case Employment Impact Comparison

Black & Veatch also estimated the economic impact of each deployment scenario developed for this study. Figure 5-2 shows that the low and high deployment scenarios result in total deployment of 2,100 MW and 4,000 MW, respectively. For a complete discussion of the deployment schedules refer to Section 4.0.

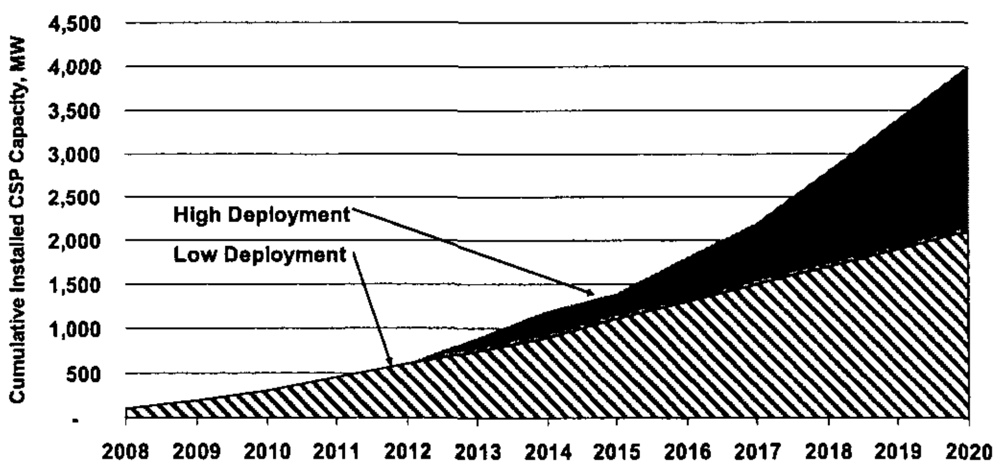

Figure 5-2
CSP Low and High Deployment Scenarios

Table 5-9 shows the total (direct plus indirect) economic impacts of the low and high deployment scenarios. The high deployment scenario generates approximately double the economic impact of the low deployment scenario, which is expected because the high deployment scenario results in about double the installed capacity of the low deployment scenario. The results of the economic impacts analysis indicate that a *significant CSP industry would be formed in California with either large-scale* deployment scenario. The deployment scenarios would result in about $7 billion and $13 billion in investment, respectively, of which an estimated $2.8 and $5.4 billion is estimated to be spent in California. This level of in-state investment has a total impact on Gross State Product of nearly $13 billion for the low deployment scenario and over $24 billion for the high deployment scenario, not including impacts from ongoing O&M expenditures. This level of investment creates a sizable direct and indirect impact to employment during construction at about 77,000 and 145,000 job-years for the low and high deployment scenarios, respectively. Ongoing operation of the CSP plants built under the deployment scenarios creates a total annual economic impact of $190 and $390 million.

Table 5-9
Total Present Value of CSP Development for Two Deployment Scenarios ($2005)

	Low Deployment	High Deployment
Construction		
Gross State Output, $1,000	12,979,000	24,617,000
Earnings, $1,000	3,556,000	6,649,000
Employment, job-years	77,300	145,000
Operation		
Gross State Output, $1,000/year	192,900	390,800
Earnings, $1,000/year	82,200	164,900
Employment, jobs	1,500	3,000

Assuming that the CSP plants would each operate for 30 years, Figure 5-3 shows the total economic impact (direct plus indirect) to earnings and employment in the construction and operation periods generated by the deployment scenarios. Figure 5-3 shows that the earnings and employment impacts are larger for the construction than operation periods. The total impacts from operation are significant at about $3.0 billion and $5.0 billion to earnings for the low and high deployment scenarios, respectively.

Additionally, the continued operation of the CSP plants results in about 45,000 job-years for the low deployment scenario and 80,000 job-years for the high deployment scenario.

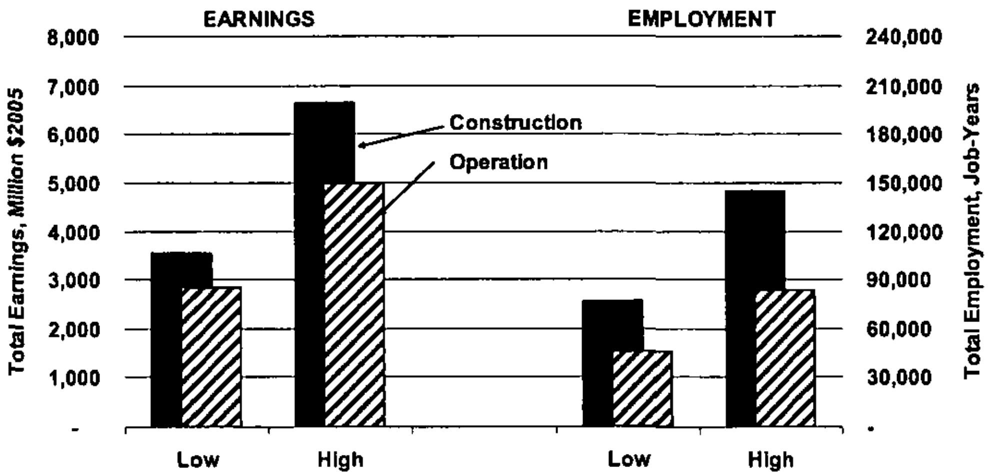

Figure 5-3
Low and High Deployment Scenarios Total Impact to Earnings and Employment

5.4 Economic Impacts Sensitivity Analysis

The assumptions for the amount of material and labor purchased inside and outside of California have a significant effect on the direct and indirect economic impacts results. Therefore, Black & Veatch developed "Low California Expenditure" and "High California Expenditure" scenarios to capture the range of possible economic impacts from the construction of CSP plants. Table 5-10 shows the assumptions for material purchased from in-state suppliers for the low, base, and high in-state expenditure scenarios.

The Low California Expenditure scenario assumes that less manufacturing capability is built in California to support CSP development. This scenario also assumes that most of the balance of plant equipment (small pumps, motors, small bore piping, etc.) is purchased from out of state suppliers. It is assumed, as with the base case, that construction and installation will be provided by in-state suppliers.

The High California Expenditure scenario assumes that more manufacturing capability is built in California than the base case assumptions. It is also assumed that most of the balance of plant equipment is purchased from in-state suppliers. All construction, installation, and most engineering are assumed to be provided by in-state suppliers.

Table 5-10
Material Expenditures in California Sensitivity Criteria, percent

Plant System	2009 CSP Plant			2011 CSP Plant			2015 CSP Plant		
	Low	Base	High	Low	Base	High	Low	Base	High
Siteworks and Infrastructure	0	0	0	0	0	0	0	0	0
Contractor Overhead	100	100	100	100	100	100	100	100	100
Heat Collection Elements	0	0	0	25	50	75	50	75	100
Mirrors	0	0	0	25	50	75	50	75	100
Metal Support Structure	25	50	75	25	50	75	25	50	75
Misc. Solar Field Equipment	30	59	85	30	59	85	30	59	85
HTF System	17	34	61	17	34	61	17	34	61
Thermal Energy Storage	23	42	59	40	75	88	40	75	88
Thermal Energy Storage Fluid	25	50	75	25	50	75	25	50	75
Power Block	2	12	14	2	12	14	2	12	14
Balance of Plant	26	50	74	26	50	74	26	50	74
Contingency	11	23	35	22	45	67	33	56	78
Engineering, Const. Mgmt	25	50	75	25	50	75	25	50	75
EPC Markup	30	30	50	30	30	50	30	30	50
Land	100	100	100	100	100	100	100	100	100
Owners	50	50	50	50	50	50	50	50	50

PUC-IR-304
DOCKET NO. 2008-0273
ATTACHMENT 1
PAGE 37 OF 69

The sensitivity analysis revealed that even with significantly lower purchase of equipment and materials from California, the construction of CSP still produces larger economic impacts. Figure 5-4 shows the impact to employment and earnings for each sensitivity case along with the base case impacts for the combined cycle plant.

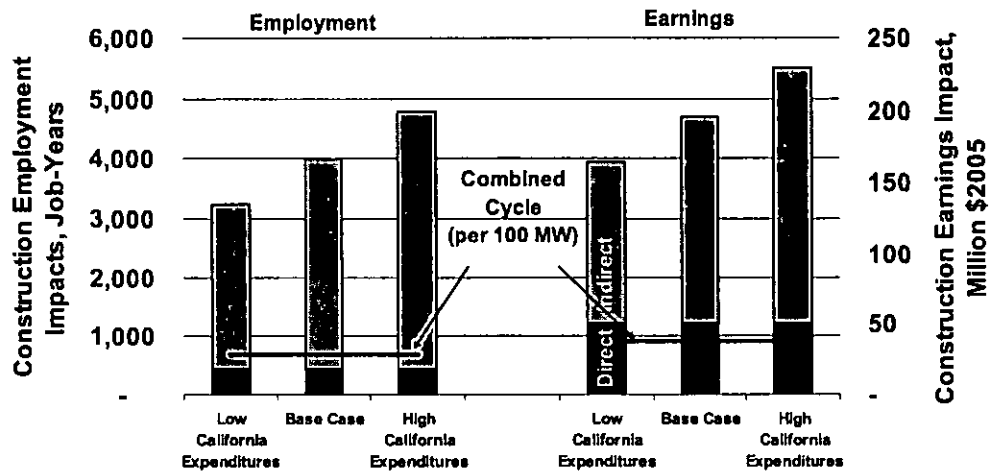

Figure 5-4
Construction Economic Impacts Sensitivity Analysis for 100 MW CSP Plant

The sensitivity analysis also revealed that the impact to Gross State Output is significantly larger than the comparative combined cycle plant. The CSP plant produced a range of \$450 million to \$800 million compared to \$420 million per 100 MW for the combined cycle plant.

Black & Veatch also developed a sensitivity analysis of the low and high CSP deployment scenarios with the low and high California expenditure cases, as shown on Figure 5-5. The sensitivity analysis revealed that there is an impact of approximately ±20 percent to employment and earnings of the low California expenditures and high California expenditures scenarios, respectively. The analysis revealed that the impact to Gross State Output is slightly higher at about ±30 percent. The sensitivity analysis shows that the economic impacts results are robust and consistently higher than the calculated impacts for combined cycle power plants even with lower purchases of goods and services from California.

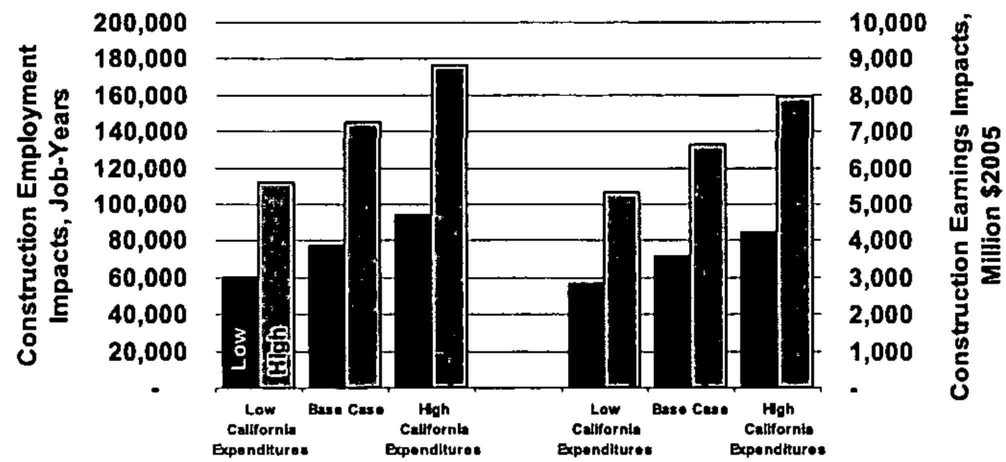

Figure 5-5
Construction Economic Impacts Sensitivity Analysis of
Low and High CSP Deployment Scenarios

5.5 Fiscal Impacts

Black & Veatch developed preliminary estimates of the fiscal impact (tax revenues) associated with the construction and continued operation of the CSP plants under the low and high deployment scenarios. To provide a point of comparison, the fiscal impacts for 2,100 and 4,000 MW of combined cycle power generation were also estimated. Fiscal impacts include the sales taxes during construction, individual income taxes paid by construction workers, individual income taxes paid by indirect jobs created by construction, individual income taxes paid by operators, individual income taxes paid by indirect jobs created during operation, and corporate income taxes assuming IPP ownership of the project. Based on data from the Tax Foundation, an individual state and local tax rate of 8.7 percent and a corporate state income tax rate of 8.84 percent have been assumed. The analysis yielded potential tax revenues of $1.3 billion for the low deployment scenario and $2.4 billion for the high deployment scenario, both in 2005 dollars. The potential fiscal impacts of constructing and operating 2,100 MW and 4,000 MW of combined cycle power plants are about $300 million and $600 million, respectively. The larger fiscal impacts for the CSP plants are a result of the larger capital cost and more labor intensive operations and maintenance of the CSP plants.

These fiscal impacts estimates are approximate and could vary significantly based on a number of factors including economic life of the CSP plants (assumed to be 30 years for this analysis), local tax abatements, changes to tax laws, corporate structure of the plant owner, and other factors.

6.0 Cost and Value of CSP Energy

This section provides the results of cost of energy calculations for CSP along with an evaluation of the time of delivery value of CSP energy. This section begins with a discussion of the Market Price Referent, the "reference price" of energy in California.

6.1 The Market Price Referent

A good starting point for discussion of the cost of renewable energy in California is the Market Price Referent, or MPR.[10] The MPR is part of the rulemaking surrounding the California Renewable Portfolio Standard (RPS). Utilities in California are not obligated to purchase renewable energy at prices above the MPR, which is a value set by the California Public Utilities Commission (CPUC) to reflect the market "all-in" (energy and capacity) price for base-load energy. If a renewable energy project has a cost to generate above the MPR, the generator can apply to the CEC for Supplemental Energy Payments (SEPs) to cover above market costs. The MPR is released after the results of the renewable energy solicitations are announced so the MPR does not affect the bids.

The MPR for 2005 was calculated with a proxy plant methodology using a natural gas fired combined cycle plant as the proxy for base-load energy. There was no simple-cycle proxy as in previous years. Instead, time of delivery (TOD) multipliers are to be applied to the baseload MPR value to come up with pricing at peak times. The all-in dollar per MWh levelized energy price for each proxy plant was calculated for 10, 15, and 20 year contract terms. The 2005 MPR value for a 20-year PPA starting in 2007 is $77.24 per MWh. The MPR also includes a 25-year natural gas price forecast, which is based on NYMEX forward futures costs for the first six years, and a combination of EIA and private forecasts for the later years. This report uses a natural gas forecast of $6.40 per MMBtu, escalated at 2.5 percent, which is equivalent to the levelized MPR natural gas forecast for 2007-2026.[11] The CPUC MPR gas forecast is the consensus forecast of California natural gas prices among the CPUC, Utilities, and public interest groups.

[10] The 2005 MPR declaration was published in March 2006 by the CPUC. It is available at http://www.cpuc.ca.gov/PUBLISHED/COMMENT_RESOLUTION/54445.htm.

[11] Levelized using the MPR weighted average cost of capital of 9.3 percent as the discount rate. The levelized forecast for MPR natural gas from 2007 to 2026 is $7.61/MMBtu, while $6.40/MMBtu escalated at 2.5 percent annually is $7.62/MMBtu levelized.

The MPR also included other assumptions about plant heat rates, debt/equity splits, and finance costs. Where possible, this report has used the same assumptions as the MPR.[12]

6.2 Cost of Energy Calculations

Black & Veatch developed a cost of energy comparison between each of the proxy parabolic trough CSP plant and comparable fossil fuel technologies. The levelized cost of energy is a present value measure of the lifecycle cost of generating power from a given plant considering the capital cost, operating costs (including fuel), capacity factor, financing cost, and incentives. The levelized cost is a useful calculation because it allows comparison of different generation technologies on an equal basis. For this analysis, the parabolic trough CSP plant was compared with simple cycle and combined cycle combustion turbines because these types of plants provide peaking and intermediate electric services similar to CSP plants. Capital cost and performance assumptions for the CSP technologies were developed in Section 2.0 and performance assumptions for the combined and simple cycle combustion turbines were provided in Table 5-3. Financial assumptions, such as cost of debt and equity, were taken directly from the 2005 MPR ruling and are listed in Table 6-1. Actual plant financing parameters may differ from MPR; however, MPR has been used in this document for consistency. For all generation technologies it was assumed that the plant would be owned by a credit worthy independent power producer (IPP) with a power purchase agreement with a California IOU.

The Energy Policy Act of 2005 contains a number of incentives for renewable energy generation[13]. Specifically, the Act increases the Investment Tax Credit (ITC) to 30 percent through December 31, 2007, for solar facilities[14]. Solar facilities had a "permanent" ITC of 10 percent before the Act was passed. Because the 30 percent ITC may not be extended, cost of energy calculations have been made assuming both a 30 percent ITC and the older 10 percent ITC.[15]

[12] We diverge only in capacity factor. The MPR uses a 92 percent capacity factor, while we use 40 percent to stay consistent with the intermediate duty cycle of CSP. At a 92 percent capacity factor, our LCOE calculations result in a price of $77 per MWh, equivalent to the MPR.
[13] 26 USC § 48 (2005).
[14] The Act also extended the Production Tax Credit (PTC) to solar facilities, but the PTC for solar expired at the end of 2005.
[15] A bill was recently introduced in the Senate (S.2401) that would extend the ITC to 2010.

Table 6-1
Financial Assumptions for Cost of Energy Calculations

Assumption	Combustion Turbine	CSP Plants
Economic Life, years	30	30
Tax Life, years	20	5
Debt Percentage	42.5%	42.5%
Cost of Debt	8.0%	8.0%
Cost of Equity	12.7%	12.7%
Weighted Average Cost of Capital (WACC) (Used as discount rate)	9.3%	9.3%
Tax Rate, combined federal and state	40.75%	40.75%
Levelized Fixed Charge Rate	14.4%	11.8%
Investment Tax Credit	N/A	30% and 10%
2007 Natural Gas Price (escalated at 2.5% annually)	$6.40/MMBtu	N/A
2015 Natural Gas Price (escalated at 2.5% annually)	$8.00/MMBtu	N/A
Inflation Rate	2.5%	2.5%
Real Discount Rate	6.8%	6.8%

Note:
All assumptions from the 2005 California Market Price Referent financial inputs.

Real and nominal levelized cost estimates for parabolic trough CSP plants and the conventional alternatives are provided in Table 6-2. The levelized costs of developing a CSP plant in 2007, 2009, 2011, and 2015 include the effects of the learning curves, which reduce the capital cost over time with increased deployment. The characteristics of the plants developed in 2009, 2011, and 2015 were used to calculate the economic impact of developing CSP plants in Section 5.0. The CSP plants have nominal levelized costs in the range of $103 per MWh to $157 per MWh with the 30 percent ITC and $115 per MWh to $176 per MWh with the permanent 10 percent ITC. This is competitive with the 2007 simple cycle combustion turbine with a levelized cost of $168 per MWh (using the MPR natural gas price of $6.40/MMBtu escalated at 2.5 percent). However, the plants have different capacity factors; the simple cycle plant provides peaking service with a

Table 6-2
*Levelized Cost Comparison**

	Capacity, MW	Storage, hours	Capacity Factor, %	Nominal Levelized Cost, $ per MWh (30% ITC)	Nominal Levelized Cost, $ per MWh (10% ITC)	Real Levelized Cost, $ per MWh (30% ITC)	Real Levelized Cost, $ per MWh (10% ITC)
Simple Cycle	85	N/A	10.0	168	168	134	134
Simple Cycle ($8/MMBtu Gas)**	85	N/A	10.0	187	187	149	149
Combined Cycle	500	N/A	40.0	104	104	83	83
Combined Cycle ($8/MMBtu Gas)**	100	N/A	40	119	119	95	95
Parabolic Trough (2007)	100	0	28.4	154	173	125	140
Parabolic Trough (2007)	100	6	40.4	157	176	127	143
Parabolic Trough (2009)	100	6	40.4	148	166	120	135
Parabolic Trough (2011)	150	6	40.4	120	134	97	109
Parabolic Trough (2015)	200	6	40.4	103	115	83	93

*Financial assumptions are essentially per MPR calculation methodology. Assumptions are provided in Table 6-1.
**$8/MMBtu is MPR gas price for 2015.

PUC-IR-304
DOCKET NO. 2008-0273
ATTACHMENT 1
PAGE 43 OF 69

10 percent capacity factor and the trough plant with storage provides intermediate service with a 40 percent capacity factor.

The CSP plants are not competitive with the combined cycle plant in the early years, but become more so in the 2015 timeframe. At a levelized gas price of $8/MMBtu, which is the MPR forecast for 2015, the combined cycle plant, at a capacity factor of 40 percent, has a levelized cost of $119/MWh. This is roughly equivalent to the $115/MWh of the CSP plant in 2015, with the permanent 10 percent ITC.

6.3 The Time of Delivery Value of CSP Energy

This section discusses the value provided by thermal storage integrated with the proxy parabolic trough CSP plant. Conceptually, thermal storage allows the plant to store energy generated during lower power demand periods and deliver this energy during high-demand hours (see Figure 6-1). Thermal storage, along with an enlarged solar field, also allows the CSP plant to operate at a higher annual capacity factor, about 40 percent with 6 hours of storage versus 28 percent for no storage. This gives the plant the ability to generate higher revenues to off-set the additional cost of the storage system. The levelized costs in Table 6-2 reveal this, as the trough plant with 6 hours of storage and without storage have roughly the same cost of energy ($157/MWh vs. $154/MWh).

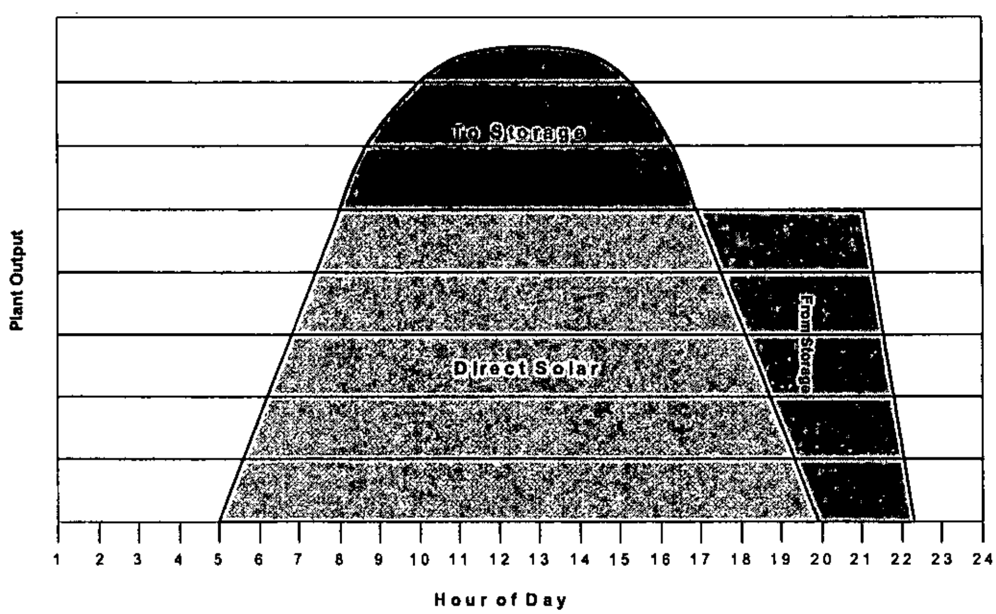

Figure 6-1
Conceptual Generation Scenario with Storage

Renewable energy generators generally fall into two categories: firm and as-available. As-available resources are resources such as wind or CSP without storage that are not controlled by the generator, while firm resources can control when they generate. PG&E lists four energy "products" allowed to bid into their 2005 renewable RFO: as-available, baseload, peaking, and dispatchable. Peaking resources must have at least a 95 percent capacity factor during the peak summer hours[16], while baseload resources have 24x7 profiles. Dispatchable resources must be available on a day-ahead schedule.

The trend in the renewable energy industry is toward a single all-in energy payment, with no separate capacity payments.[17]. In the past, firm resources would receive capacity payments as well as energy payments. The lack of capacity payments makes it more difficult to assign a dollar value to a firm resource versus an as available resource, especially if both of those resources have similar time of delivery (TOD) profiles. The MPR methodology for assigning value to energy is based on the generator's TOD profile, with multipliers for various time periods. For example, a plant that ran only during peak hours would have an MPR price of $110/MWh, based on SCE's TOD factor of 1.425 applied to the 2007 MPR ($77.24/MWh)

The MPR prices for a CSP plant with 6 hours of storage and a CSP plant without storage were determined by applying the TOD multipliers to Excelergy's production profile. Surprisingly, both CSP plants have approximately the same MPR energy value of about $87/MWh.[18] Examination of the generation profile data show that, while the plant with storage generates more higher-value energy during peak hours, it also generates more lesser-value energy during non-peak hours. Although there is no separate capacity credit that can be assigned to the CSP plant with storage, it clearly has more value to the utility than an "as available" CSP plant without storage, despite their similar MPR prices. The plant with storage qualifies as a firm "peaking" resource under PG&E's rules,[19] generating firm power during peak summer hours. PG&E explicitly states a preference for peaking resources in its 2005 RFO, as it rates peaking resources as a "high" need and as-available as a "low." Future MPR methodologies may return to including assigning explicit capacity value, which allow solar thermal with storage to receive a more explicit capacity credit.

[16] Noon to 8PM, PDT, June through September.
[17] PG&E, SCE, SDG&E, SMUD and LADWP all have a single all-in payment structure for renewable energy, and the MPR no longer contains a peaking unit. Other IOUs are also moving to all-in payments.
[18] This value is using the 2005 MPR and SCE's TOD multipliers. PG&E's and SDG&E's multipliers are similar.
[19] Excelergy modeling shows that 6 hours of storage is needed to ensure 95 percent availability during peak times.

7.0 Environmental and Hedging Benefits

CSP plants provide environmental benefits by generating power without producing criteria and CO_2 air emissions. In addition, the use of fixed cost renewable energy generation, such as CSP or wind, can decrease fossil fuel use and provide a hedge against fossil fuel price increases. While CSP plants may have environmental benefits due to emissions reductions, they do require significant land area. A 100 MW CSP plant is estimated to cover approximately 800 acres (comprised mostly of the solar field) while a 500 MW combined cycle plant would occupy about 20 acres.[20]

7.1 Reduction in Criteria and CO_2 Air Emissions

A key benefit of the use of CSP plants in California is the potential to reduce the amount of criteria and greenhouse gas emissions. The installation of CSP may reduce air emissions if generating power from CSP plants *offsets* generation from fossil fueled plants.[21] For this calculation of emissions reductions, it has been assumed that the CSP plants will displace generation by combined cycle plants with an average heat rate of 7,000 Btu/kWh. Typical permitted emissions requirements for a new plant in southern California were obtained from the California Air Resources Board, and are shown in Table 7-1.[22] Based on these emission rates, the table also shows the amount of emissions displaced by annual generation from a single 100 MW trough plant with six hours of storage, as well as for the low deployment and high deployment scenarios of 2,100 MW and 4,000 MW of CSP generation capacities, respectively.

The estimates in Table 7-1 are conservative because of the assumption that CSP would displace emissions from new plants. CSP plants could offset generation from older thermal natural gas or oil fueled generation with average heat rates equal to or exceeding 10,000 Btu per kWh, which would increase the emissions offset by about 30 percent. Furthermore, the older plants are unlikely to have modern air emissions control technology that would be required on new plants. Thus, the increase in emissions offset by assuming displacement of older generation would likely exceed 30 percent.

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[20] Of course, the land requirements for the combined cycle plant do not include the land required for acquisition of natural gas.

[21] While emissions reduction can be more complicated when cap-and-trade systems (such as the RECLAIM system for NOx trading in the South Coast Air Quality Management District) are involved, it is generally correct to assert that a CSP plant that offsets a natural gas-fired plant will result in less emissions.

[22] Permitted air emissions requirements are available at the California Air Resources Board at: www.arb.ca.gov/bact/bactnew/rptpara.htm

Table 7-1
Emissions Reduction by CSP Plants

Pollutant	Proxy Fossil Plant Emissions Rate		CSP Plant Capacity		
	lb/MMBtu	Parts per million	100 MW (tons/year)	2,100 MW (tons/year)	4,000 MW (tons/year)
NO_x	0.006	2	7.4	156	297
CO	0.004	4	4.5	95	181
VOC	0.002	1.4	2.6	54	103
CO_2	154		191,000	4,000,000	7,600,000

Notes:
1. Proxy Fossil Plant assumed to be a combined cycle combustion turbine with a heat rate of 7,000 Btu/kWh.
2. CSP plants assumed to operate at 40 percent capacity factor.

7.2 Hedging Impact of CSP on Natural Gas Prices

The installation of renewable energy power generation that does not use fossil fuels has the potential to provide a natural hedge against fossil fuel price increases. Generally, renewable energy generators, particularly CSP that serves peak demand, offset the use of natural gas fueled generators. Therefore, this section focuses on the analysis of CSP as a hedge against natural gas price increases. An overview of the consumption and price of natural gas in the US and California is provided first. The two primary hedging effects are then analyzed: the potential decline in prices and volatility from decreased demand, and the hedging effect that the installation of CSP has on the generation portfolio.

7.2.1 Natural Gas Use in the United States

Natural gas is a primary fuel for the US residential, commercial, industrial, and power generation sectors. Figure 7-1 shows the growth in overall natural gas demand since 1990. Gas consumption for power generation is a major part of the growth, accounting for 5,721 trillion Btu (TBtu) in 2002 compared with 3,342 TBtu in 1990, a 70 percent increase. Demand growth is expected in all sectors, but demand from electricity generators is expected to grow the fastest, increasing 90 percent by 2025. Various reports project demand to increase to 28 to 31 TCF per year by 2025.

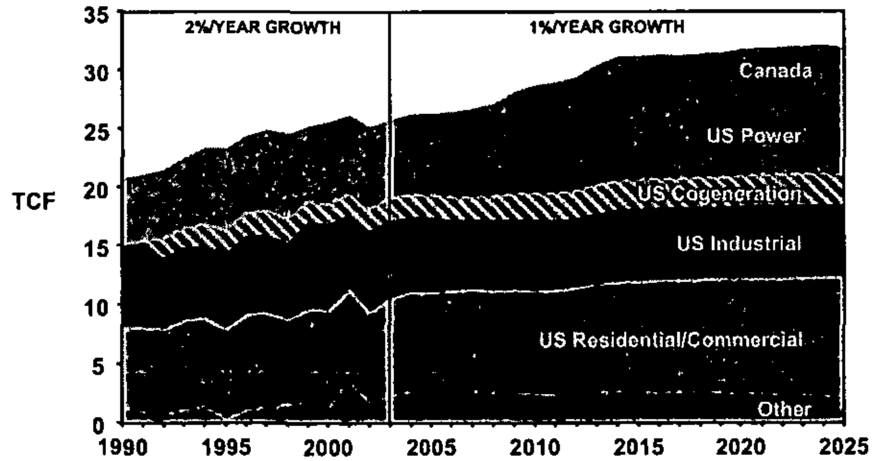

Figure 7-1
Historic and Forecast Natural Gas Demand by Sector (NPC 2002)
Source: American Gas Association

Natural gas consumption for power generation has increased because the development of relatively low cost, high-efficiency combined cycle combustion turbine technology has made natural gas an economic alternative to oil and coal. Furthermore, gas is the cleanest burning of the fossil fuels and is favored globally for its relatively low greenhouse gas emissions when compared with other fossil fuels. Figure 7-2 shows that new electric generating capacity installed in the US for 1990-2006 was primarily natural gas fueled. Despite the large increase in natural gas fueled power generation, coal still provides about 50 percent of the electric supply for the US, followed by nuclear at about 20 percent, and natural gas fueled power stations at about 18 percent.[23]

7.2.2 *Natural Gas Use in California*

California currently consumes about 10 percent of the total natural gas used in the US – about 2.36 TCF in 2004. It is estimated that in the next decade, California will add five million people to its current population of about 35 million. The added population will need power and fuel; three-quarters of California's electricity growth and most of the state's natural gas growth will be driven by the need to serve these new citizens.

California is particularly vulnerable to natural gas price fluctuations and supply constraints because of its reliance on out-of-state sources. Currently, about 85 percent of the consumption is provided by imports. Figure 7-3 shows a breakdown of the source of natural gas for the California market.

[23] For 2004, EIA

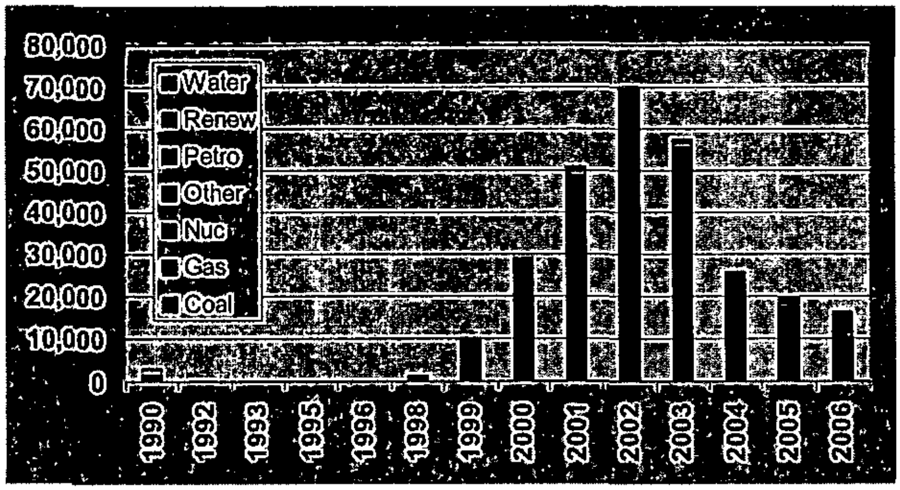

Figure 7-2
Breakdown of US Capacity Additions by On-Line Date (MW)
Source: US Department of Energy, Energy Information Administration

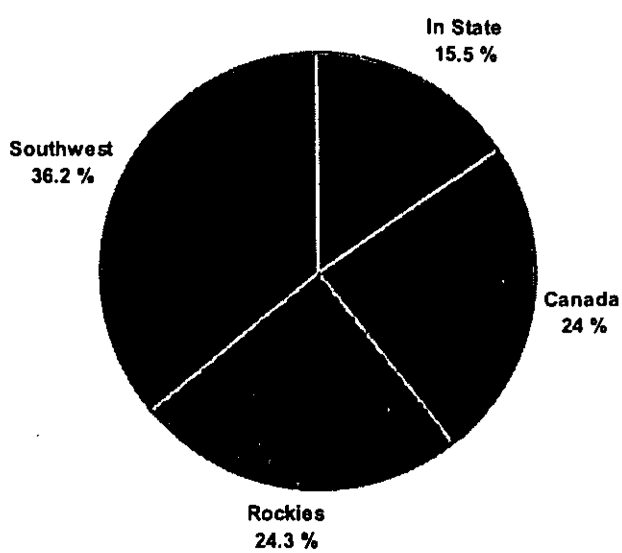

Figure 7-3
California's Natural Gas Sources for 2004
Source: California Energy Commission

The California Energy Commission (CEC) has passed a moratorium on the construction of coal fueled power generation in the state and the import of power produced by coal fueled plants. By removing coal as a possible fuel for new power generation, natural gas fueled or renewable energy will be required to meet the growing demand for power in the state.

7.2.3 *Natural Gas Prices and Price Volatility*

Natural gas is actively traded on commodities markets throughout the world, such as the New York Mercantile Exchange (NYMEX) or the Chicago Board of Trade (CBOT). The fuel is bought and sold for immediate delivery, the "spot market," and options on future delivery ("futures contracts") are traded. Long-term price trends are typically caused by factors that affect supply and demand, such as economic activity and changes to natural gas production and storage. Figure 7-4 shows an upward long-term trend of natural gas prices in California. The figure also shows the impact of short-term phenomena on natural gas prices. The chart also shows the short-term effect of supply/demand shock during the California energy crisis in 2000 and 2001. The surge in the use of natural gas to meet power demand created short-term supply constraints and, thus the price spikes shown in the chart.

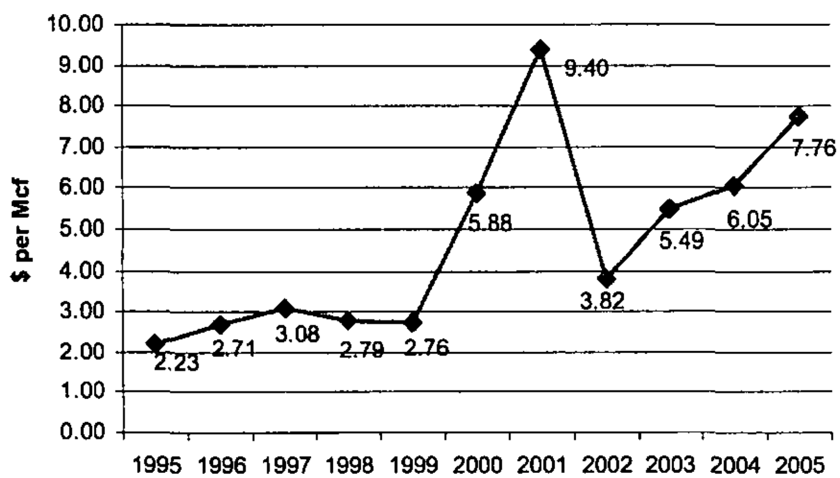

Figure 7-4
California Electric Power Sector, Annual Average Natural Gas Prices, $ per MCF
(Source: EIA[24])

[24] 2005 data point is for Jan-Nov, as Dec had not been reported as of 4/6/2006.

Short-term market price fluctuations, or volatility, are caused by random factors such as weather, expectations of future supply, geopolitical events, etc. The ability of the market to absorb short-term supply shocks caused by these factors is directly impacted by the relationship of supply and demand in the market. For example, a relatively small change in price would be expected if a short-term supply shock occurred and supply significantly exceeded demand. However, a relatively large price impact could be expected if supply and demand were in balance. The US is currently in the latter situation. While demand has increased, production has been relatively constant.

A combination of long-term and short-term factors has led to a consistent and significant increase in natural gas prices in recent years. The average wellhead natural gas price rose from around $2 per MMBtu in the 1990s to $7.51 per MMBtu in 2004.[25] The 6 year NYMEX forward curve indicates that the price at the Henry Hub will remain in the $5 to $8 per MMBtu range, while the EIA's latest forecast[26] projects that wellhead prices will average $5 MMBtu in the coming 20 years.

7.2.4 The Hedging Impact of CSP Deployment in California

There are two basic benefits that the large scale deployment of CSP could provide to the California natural gas and electric markets: reduction of natural gas prices from decreased demand; and lower exposure to natural gas price fluctuations from a more diversified electric generating portfolio. This section includes a brief analysis of each of these potential impacts and a high-level estimate of the potential value of these impacts.

7.2.4.1 Impact on Natural Gas Prices. The deployment of non-fossil fueled power generation can decrease or slow the growth in demand for fossil fuels if power generated by fossil fueled plants is off-set by renewable energy generators. Several recent studies suggest that there could be a price decrease of between one and four percent for each 1 percent decline in demand.[27,28] Therefore, based on a 1 percent reduction in gas price for a 1 percent reduction in nationwide gas usage, the deployment of 4,000 MW of CSP in California could result in a total reduction of approximately $60 million per year for

[25] US Energy Information Administration (EIA) www.eia.doe.gov.
[26] 2006 Annual Energy Outlook. Released December 2005. www.eia.doe.gov.
[27] *Easing the Natural Gas Crisis: Reducing Natural Gas Prices through Inceased Deployment of Renewable Energy and Energy Efficiency* Ryan Wiser, Mark Bolinger, Matt St. Clair., Berkley National Laboratory, LBNL-56756, January 2005.
[28] Dr. Ryan Wiser, Scientist, Lawrence Berkeley National Laboratory, testimony to Senate Committee on Energy and Natural Resources, *Easing the Natural Gas Crisis: Reducing Natural Gas Prices Through Electricity Supply Diversification,* March 8, 2005.

natural gas expenditures in California, assuming a natural gas price of $6.40 per MMBtu.[29] If the natural gas price reduction were to be in the range of 4 percent for each 1 percent reduction in nationwide gas usage, the savings in gas cost to California could be four times higher. These savings in California are based on average savings for US consumers. However, savings per MMBtu could be higher in California than the national average. Dr. Ryan Wiser, in private communication, wrote, "Though reductions in California natural gas demand will have national price impacts that spill over to the state, the impact on California natural gas prices may be somewhat higher than the national impact if the natural gas transportation infrastructure serving California is constrained.[30]"

7.2.4.2 Portfolio Hedging Impact. Electricity is provided to California consumers primarily by natural gas, imported coal fueled power, and hydroelectric energy. Figure 7-5 shows the source of electricity generation in California.

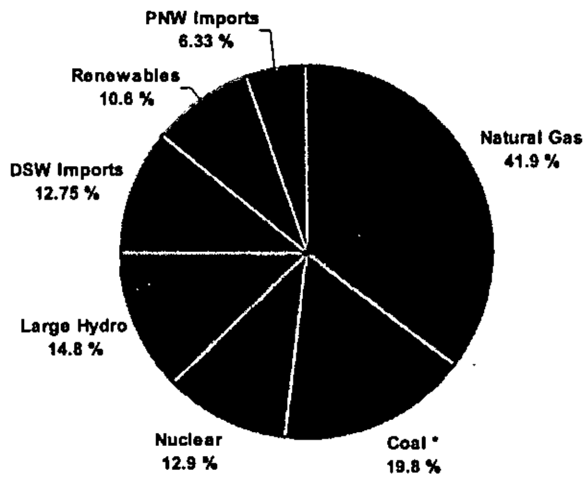

Figure 7-5
Generation Sources for California Electricity in 2004
Source: California Energy Commission
*Intermountain and Mohave coal plants are considered in-state, since they are in California control areas.

[29] Taking the US gas consumption in 2004 to be 23,000 trillion Btu, and assuming a proxy of a combined cycle plant heat rate of 7,000 Btu/kWh, the amount of natural gas displaced by a 100 MW CSP plant operating at a 40 percent capacity factor is 2,400 billion Btu/yr, or 0.01 percent of the US gas consumption. Likewise, the amounts of natural gas displaced by 2,100 MW and 4,000 MW are 52,000 billion Btu/yr and 99,000 billion Btu/yr, (0.2 percent and 0.4 percent of national consumption), respectively. At 1 percent price reduction for each one percent of demand reduction, this would equate to a 0.01 percent price reduction resulting from a 100 MW plant, a 0.2 percent price reduction for a 2,100 MW CSP deployment, and a 0.4 percent price reduction for a 4,000 MW CSP deployment.

[30] Dr. Ryan Wiser in an email to Dr. Larry Stoddard, Black & Veatch, December 13, 2005.

Natural gas fueled power generation provides the largest share of electricity in California - over 40 percent. The natural gas fueled generation fleet consists of older steam thermal electric units, combined cycle combustion turbines, and simple cycle combustion turbines. Depending upon which utilities purchase the output from new CSP plants, the deployment of CSP could off-set the construction of new combined cycle and simple cycle plants or the use of older less-efficient steam thermal units.

Hydroelectricity is also an important element of California's energy portfolio. Between 1983 and 2002, in-state hydropower provided an annual average of approximately 37,000 GWh, or 15 percent, of the electricity used in California. During this same period, hydroelectric generation ranged from 9 percent to 30 percent of total state electricity sales, depending on hydrologic conditions. Hydropower's important energy attributes include peaking reserve capacity, spinning reserve capacity, load following capacity, transmission support, and extremely low production costs.

Due to the seasonal and annual variation in hydrologic cycles, hydroelectric production varies widely from year to year. Figure 7-6 shows the annual variation in capacity factor for hydroelectric plants in the US. When precipitation runoff is bountiful, hydroelectric generation is used and other generating plants, mostly gas-fired facilities, are idled. When hydroelectric energy generation is low, intermediate and peaking generating plants make up the difference.

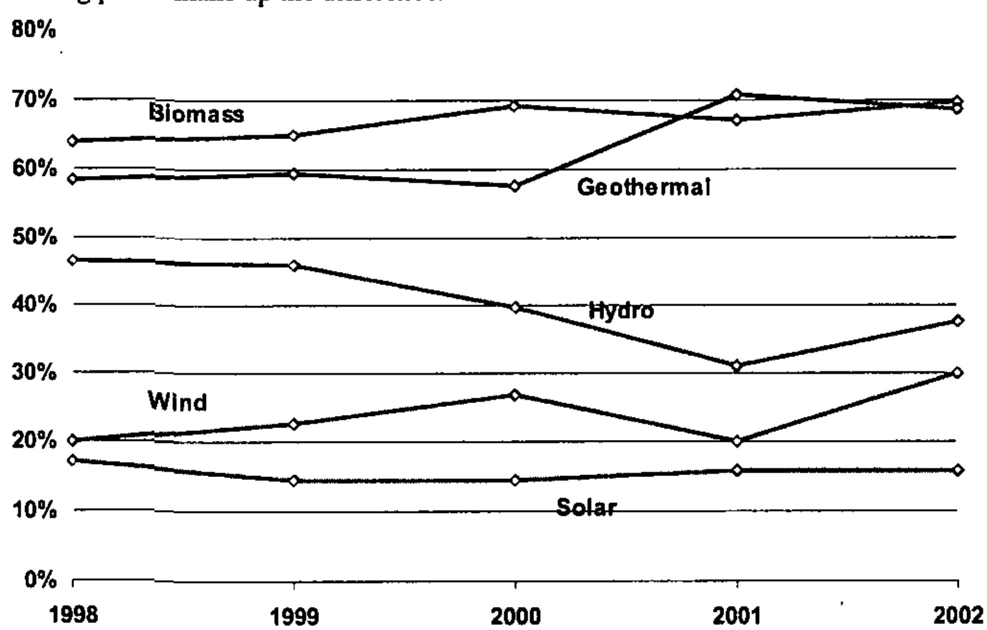

Figure 7-6
Annual Variation in Renewable Energy Project Capacity Factors
Source: EIA, REA 2002

A diversified portfolio of generation technologies and energy sources decreases the total risk of the portfolio to fluctuations in the value of any one component of the portfolio. Black & Veatch estimated the relative portfolio hedging effect of CSP to the California electric system based upon plant production cost data obtained from Platt's and the CSP deployment scenarios developed in Section 4.0.[31] The total annual production cost, that is, fuel plus non-fuel variable O&M cost, but not including capital costs, was calculated for the current California generation portfolio, the low CSP deployment and high CSP deployment scenarios. This calculation was then repeated for three natural gas price scenarios. Figure 7-7 provides the total annual production cost compared to the base case generation portfolio. As shown in Figure 7-7, the total cost increases by 32 percent for the base case portfolio and by 27 percent under the high CSP deployment scenario – a difference of 5 percentage points. Given a total annual production cost of about $12 billion under the high fuel scenario, this difference equates to about $500 million annually. The benefit is somewhat smaller for the low CSP deployment scenario, but still positive. Thus, the benefit of portfolio diversification can be significant depending on the volatility of the other components of the portfolio.

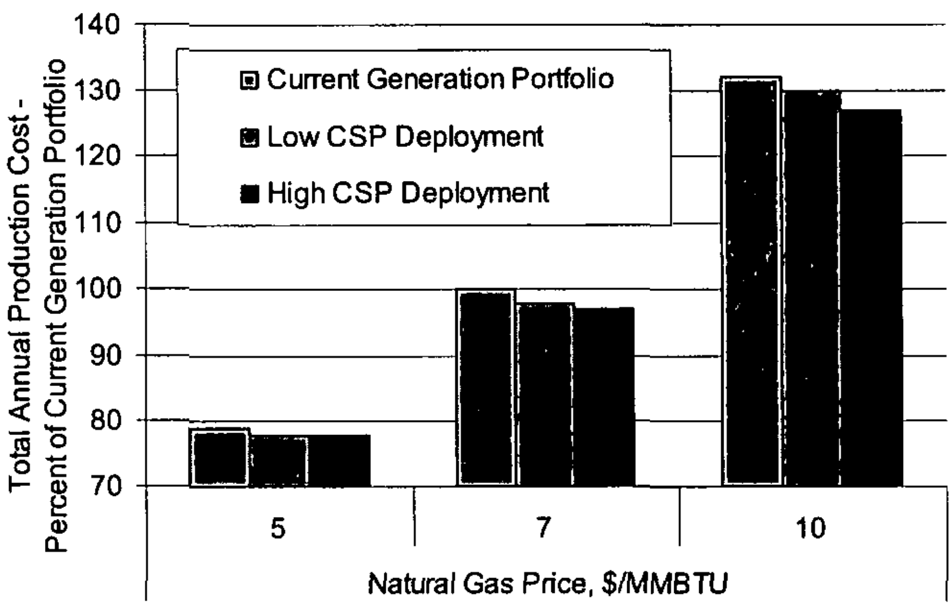

Figure 7-7
Effect of CSP Deployment on Statewide Generation Cost (Current Portfolio with $7.00/MMBtu gas = 100)

[31] Plant production cost data by fuel type provided by Platt's and available through the Platt's Power Outlook Research Service at: www.platts.com.

8.0 Conclusions

The purpose of this study was to determine the economic and environmental impacts on California resulting from the installation of concentrating solar power plants. The primary focus was on economic and employment impacts and the comparison of these findings with the corresponding impacts from conventional gas fired generators that would otherwise be employed. To ensure that projected installation scenarios were realistic, the electricity supply characteristics of potential CSP technology variants were examined and the availability of California solar resources to support estimated solar plant output was addressed. The environmental impacts of power production were quantified as well as the possible "hedge" value against increases in natural gas price. Having completed the foregoing, Black and Veatch reaches the following conclusions:

- California has high quality solar resources sufficient to support far more concentrating solar installations than either of the 2,100 MW or 4,000 MW capacity scenarios postulated for this study.
- Depending on the CSP plant interconnection point and the load profile of the local electricity provider, concentrating solar power installations with 6 hours storage could perform peaking and/or intermediate generation roles for the utility.
- Investment in CSP power plants delivers greater return to California in both economic activity and employment than corresponding investment in natural gas equipment:
    - Each dollar spent on CSP contributes approximately \$1.40 - \$1.50 to California's Gross State Product; each dollar spent on natural gas plants contributes \$0.90 - \$1.00 to Gross State Product.
    - The 4,000 MW deployment scenario was estimated to create about 3,000 permanent jobs from the ongoing operation of the plants.
- Operational period expenditures on operations and maintenance create more permanent jobs than alternative natural gas fueled generation.
- For each 100 MW of generating capacity, CSP was estimated to generate 94 permanent jobs compared to 56 jobs and 13 jobs for combined cycle and simple cycle plants, respectively.
- Energy delivered from early CSP plants (startup in 2007) costs more than that delivered from natural gas combined cycle plants[32] (\$157 per MWh

[32] Based on MPR gas prices for 2007, \$6.40/MMBtu, and assuming a 100 MW CSP plant with 6 hours storage and a 500 MW combined cycle plant. Both CSP and combined cycle plants operate at 40 percent capacity factor. All dollars are \$2005.

vs. $104 per MWh, based on a 30 percent ITC for CSP). With technology advancements, improvements to CSP construction efficiency, and with higher gas prices consistent with 2015 MPR projections, CSP becomes competitive with combined cycle power generation ($115 per MWh vs. $119 per MWh, even with the permanent 10 percent ITC). Most of the economic and employment advantages are still retained.

- CSP plants are a fixed-cost generation resource and offer a physical hedge against the fluctuating cost of electricity produced with natural gas.
- Each CSP plant provides emissions reductions compared to its natural gas counterpart; the 4,000 MW scenario in this study offsets at least 300 tons per year of NO_x emissions, 180 tons of CO emissions per year, and 7,600,000 tons per year of CO_2.

The economic and employment benefits, together with delivered energy price stability and environmental advantages, suggest that the CSP solar alternative would be a beneficial addition to California's energy supply. While early CSP plants are more costly than their traditional gas counterparts, subsequent plants are estimated to become nearly cost competitive on a levelized cost of energy basis.

Appendix A
Technology Assessment

Appendix A
Technology Assessment

This CSP technology assessment was aimed at characterizing the CSP technologies for the economic impact assessment tasks. Performance, commercial readiness, cost, reliability, and technical risk have been characterized. Six technologies are discussed in this section.

- Parabolic trough without storage or hybrid fossil.
- Parabolic trough with storage.
- Parabolic trough with hybrid fossil.
- Parabolic dish.
- Power tower.
- Concentrating photovoltaic (CPV).

Concentrating solar thermal power plants produce electric power by converting the sun's energy into high temperature heat using various mirror or lens configurations. For solar thermal systems (trough, dish-Stirling, power tower), the heat is transferred to a turbine or engine for power generation. Thermal plants consist of two major subsystems: one that collects solar energy and converts it to heat, and another that converts heat energy to electricity. CPV plants provide power by focusing solar radiation onto a photovoltaic (PV) module, which converts the radiation directly to electricity. Either mirrors or lenses can be used to concentrate the solar energy for a CPV system.

All CSP systems make use of the direct normal component of solar radiation, that is, the radiation that comes directly from the sun. Concentrating systems are unable to use global radiation, which is reflected radiation. Global radiation is present on sunny days and on cloudy days. Direct normal insolation (DNI) is available only on sunny days. Concentration of DNI allows a solar system to achieve a high working fluid temperature, or, in the case of CPV, allows expenditure for higher efficiency CPV cells since the cell area is small compared with the collector (mirror or lens) area. The need to focus DNI requires that collector systems track the sun. Parabolic trough systems use single-axis trackers to focus radiation onto a linear receiver. Dish-Stirling and power tower systems use two-axis trackers. The CPV systems discussed in this report use two axis tracking to achieve point focus images on PV cells. Single axis, line focus CPV systems have been built, but do not appear to have the long term commercial potential that the two axis tracking CPV systems have.

Because trough and power tower systems collect heat to drive central turbine-generators, they are best suited for relatively large plants—50 MW or larger. Dish and CPV are modular in nature, with single units producing power in the range of 10 kW to 35 kW. Thus, dish and CPV systems could be used for distributed or remote generation applications, and can be sited as large plants by aggregating many units. Trough and tower plants, with their large central turbine generators and balance of plant equipment, have a cost advantage of economy of scale—that is, cost per kW goes down with increased size. Dish and CPV systems have the potential advantage of mass production of individual units, similar to the mass production of automobiles

Trough and tower systems have the potential advantage over dish and CPV systems in that an amount of dispatchability can be designed into the system with thermal storage or the use of hybrid fossil. Dispatchability allows the solar plant to generate electricity during short duration cloudy periods or to generate electricity into the evening after sunset. This gives the plant potential to receive capacity credit, and provides the ability to more closely match the utility peak load profile. At this time, dish-Stirling systems have not been configured to provide hybrid fossil capability. CPV systems could, of course, make use of battery energy storage; however, battery storage is comparatively inefficient and expensive, and has not been considered in this study. Should battery storage system costs decrease substantially, and efficiency increase, the use of storage with CPV would certainly be an option in the future.

A.1 Parabolic Trough Systems

Parabolic trough systems concentrate DNI using single axis tracking, parabolic curved, trough-shaped reflectors onto a receiver pipe or heat collection element (HCE) located at the focal line of the parabolic surface. A high temperature heat transfer fluid (HTF) picks up the thermal energy in the HCE. Heat in the HCE is used to make steam in the steam generator. The steam drives a conventional steam-Rankine power cycle to generate electricity. Figure A-1 shows a row of trough collectors. A collector field contains many parallel rows of troughs connected in series. Rows are typically placed on a north-south axis, allowing the single-axis troughs to track the sun from east to west during the day.

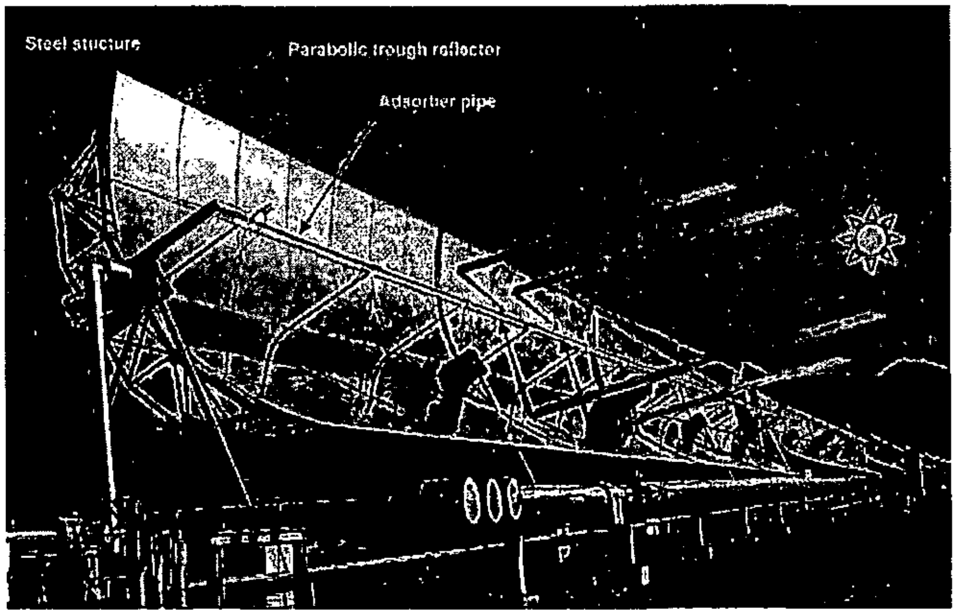

Figure A-1
Photo of Parabolic Trough System
(Source: NREL)

A.1.1 SEGS Plants

The largest collection of parabolic systems in the world is the Solar Energy Generating Systems (SEGS) I through IX plants in the Mohave Desert in southern California. The SEGS plants were built in the 1985 to 1991 time frame. Figure A-2 shows the Kramer Junction site with five 30 MW SEGS plants. The largest of the SEGS plants, SEGS IX, located at Harper Lake, is 80 MW. All of the SEGS plants are "hybrids," using fossil fuel to supplement the solar output during periods of low solar radiation. Each plant is allowed to generate 25 percent of its energy annually using fossil fuel. With the use of the fossil hybrid capability, the SEGS plants, during Southern California Edison (SCE) on-peak hours, have exceeded 100 percent capacity factor for more than a decade, with greater than 85 percent from solar operation.

In general, the SEGS plants are operating well. Operation and maintenance (O&M) costs have dropped sharply over time, coincident with performance gains. Although component reliability has generally been good, there have been issues. Modifications have been made to improve the lifetimes of mirrors and receivers. New models of HCEs from current suppliers appear to perform better than the original HCEs, with evidence of significantly reduced failure rates. The availability of spare parts was limited in the early 1990's due to the commercial failure of the supplier. With the development of new suppliers, plant operation has been excellent. Development of improved components and subsystems has also contributed to performance gains over the last decade.

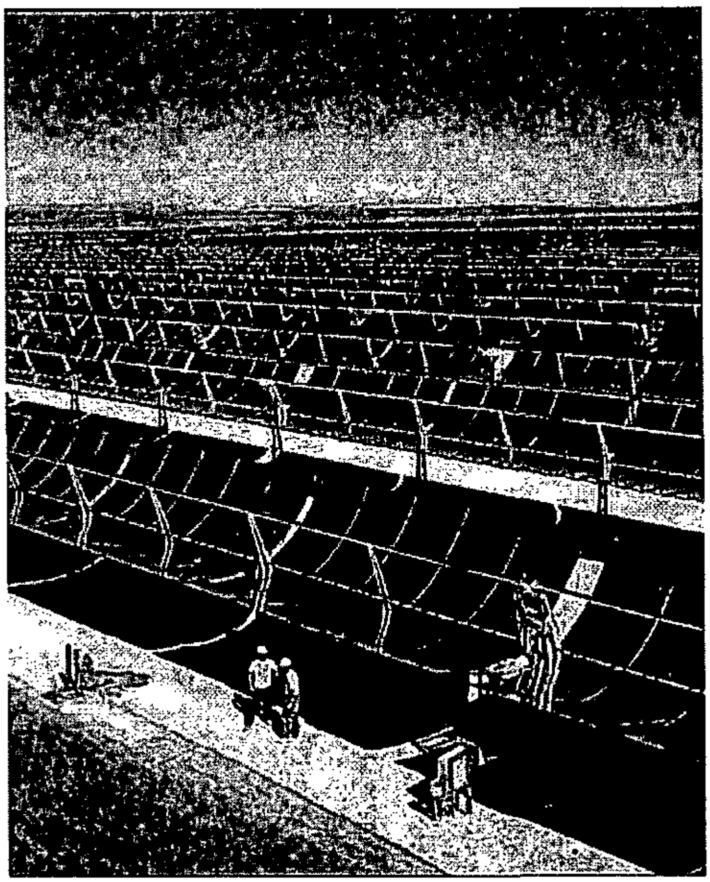

Figure A-2
Kramer Junction Trough Plant
(Source: NREL)

A performance history from 1985 to 2003 for the Kramer Junction plants is shown on Figure A-3. The period from 1985 to 1990 has low generation because plants were being brought on-line during that period. Since 1991, energy production has been quite consistent, with the low generation in 1992 resulting from low DNI because of the worldwide effects of a volcanic eruption in the Philippines.

A.1.2 Planned Trough Plants

There are several commercial projects in the planning or active project development stage. A 1 MW plant has been constructed in Arizona, with the plant currently in startup. Plants in the development stage include a 64 MW plant under construction in Nevada and a several 50 MW plant to be constructed in Spain. Indications are that the early Spanish plants will include 7 hours of thermal storage. Other projects in various stages of planning include integrated solar combined cycle system (ISCCS) in southern California, India, Egypt, Morocco, Mexico, and Algeria. In addition, there are plans for a series of SEGS type plants in Israel.

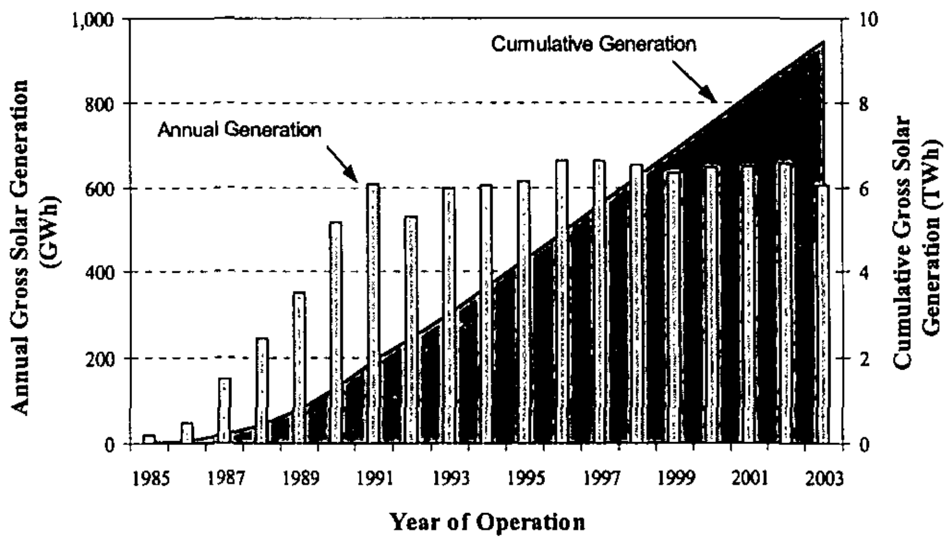

Figure A-3
Kramer Junction Annual Performance[33]

A.1.3 Trough Infrastructure Status

Parabolic trough systems are considered commercially available for industrial applications. The primary developers of this technology include Solargenix Energy (USA), Solel Solar Systems (Israel), and Solar Millennium (Germany). Suppliers of components for trough systems include reflector supplier Flabeg (Germany) and receiver suppliers Schott Glass (Germany) and Solel Solar Systems.

The currently planned technology, for thermal storage, is the molten salt two-tank system. This provides a feasible storage capacity of up to 12 hours and is considered to have a low-to-moderate associated risk.

[33] Kearney, D., Price, H., "Advances in Parabolic Trough Solar Power Technology," Advances in Solar Energy. Vol 16, Kreith, F., Goswami, D.Y. (Eds.), ASES, Boulder, Colorado, 2005.

Water requirements depend on the design and configuration of the trough system. If wet cooling is used, water consumption is about 2.8 m^3/MWh, similar to conventional steam plants; in addition, about 0.14 m^3/MWh of water is needed for washing the solar field. Dry cooling reduces water consumption drastically, but also reduces performance and increases cost.

Siting requirements for a parabolic trough system include level land, with less than 1 percent slope desirable. Solar fields are typically graded in two or more terraces for a full plant. The cost for grading is a small portion of the total cost (for relatively flat sites).

A.2 Parabolic Dish-Engine Systems

A solar parabolic dish-engine system comprises a solar concentrator (or "parabolic dish") and the power conversion unit (PCU). The concentrator consists of mirror facets which form a parabolic dish, which redirects DNI to a receiver mounted on a boom at the dish's focal point. The system uses a two-axis tracker such that it points at the sun continuously.

A parabolic dish-engine system using an efficient Stirling engine is shown on Figure A-4. The PCU includes the thermal receiver and the engine-generator. In the solar receiver, radiant solar energy is converted to heat in a closed hydrogen loop. The heated hydrogen drives the Stirling engine-generator. Because the PCUs are air cooled, there is no cooling water requirement as is necessary for the large, central power blocks associated with trough and power tower technologies. Thermal storage is not currently considered to be a viable option for dish-Stirling systems.

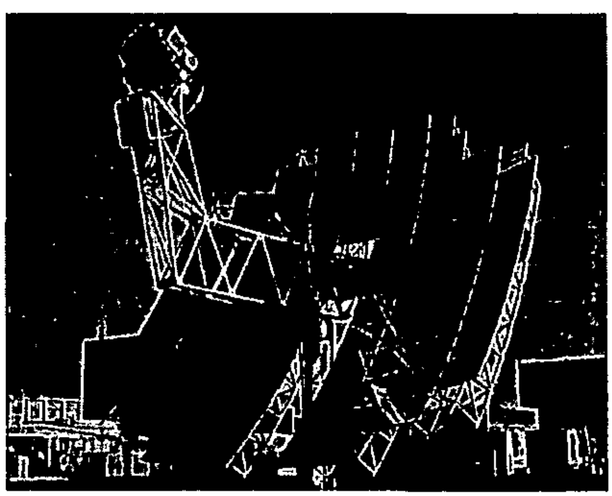

Figure A-4
Dish-Stirling System
(Source: NREL)

Relatively level land is preferable for construction and maintenance ease; however, siting requirements on slope are likely less significant than those for trough and tower systems.

Individual dish-Stirling units range in size from 10 to 25 kW. Because they can operate independent of power grids, they can be used for remote applications as well as grid connected applications. With their high efficiency and modular construction, the cost of dish-engine systems is expected to be competitive in distributed markets. Stirling Engine Systems (SES), the principal dish-Stirling developer in the United States, projects that the cost of dishes will decrease dramatically with hundreds of MWs of central station, grid connected deployment.

There are no operating commercial dish-Stirling power plants. Recently installation was completed on a six dish test deployment at Sandia National Laboratories (SNL) in Albuquerque. This development is under a joint agreement between SES of Phoenix and SNL. On August 2, 2005, Southern California Edison publicly announced the completion of negotiations on a 20 year power purchase agreement with SES for between 500 to 850 MW of capacity (producing 1,182 to 2010 GWh/year) of dish/Stirling units. On September 7, 2005, SES announced a contract with San Diego Gas & Electric to provide between 300 and 900 MW of solar power using the dish technology. Pricing for these power purchase agreements remain confidential. This large deployment of dish Stirling systems is expected to drastically reduce capital and O&M costs and to result in increased system reliability.

Other planned deployments of dish-engine systems included contracted deployments of a 25 kW demonstration dish by SES at Eskom in South Africa and a 10 kW Schlaich Bergermann und Partner (SBP) dish providing power to the grid in Spain. Proposed or planned deployments include a 10 kW SBP dish in France and a 10 kW SBP dish in Italy.

A.3 Power Tower Systems

A power tower uses thousands of sun-tracking mirrors called heliostats to redirct DNI to a receiver at the top of a tower. In the most recent receiver deployment, a molten nitrate salt HTF heated in the receiver is used to generate steam, which, in turn, was used in a conventional turbine generator to produce electricity. An earlier power tower generated steam directly in the receiver; however, the current US design uses molten nitrate salt because of its superior heat transfer and energy storage capabilities. Commercial power tower plants can be sized to produce anywhere from 50 to 200 MW of electricity. Systems with air as the working fluid in the receiver or power system have also been explored in international research and development programs. A schematic diagram of the power tower technology is shown on Figure A-5. Figure A-6 is a photograph of the 10 MW Solar Two prototype molten salt system.

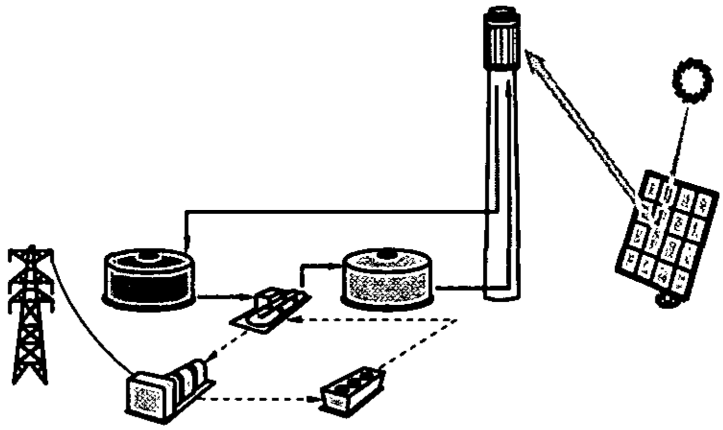

Figure A-5
Power Tower System Schematic
Source: Adapted from SunLab (SNL and NREL)

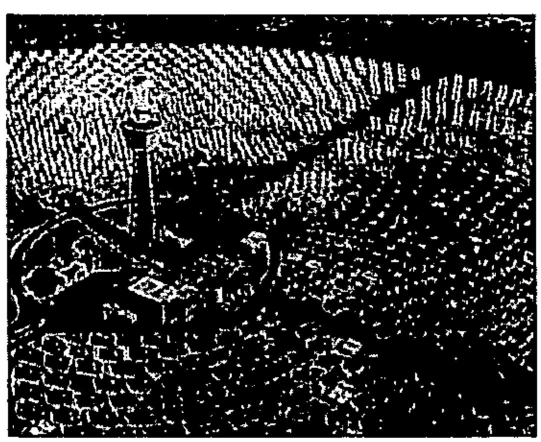

Figure A-6
10 MW Solar Two Power Tower System
(Source: NREL)

An advantage of power tower plants is that molten salt can be heated to 1,050 °F, with steam generation at 1,000 °F, which is utility standard main steam temperature. This results in a somewhat higher cycle efficiency than is achievable with the lower temperature (about 735 °F) steam achievable with a trough system. Furthermore, power towers have the advantage that the molten salt is used both as the HTF and as the storage medium, unlike the trough system which uses a high temperature oil as the HTF, and requires oil-to-salt and salt-back-to-oil heat exchange for thermal storage. The result is that storage is less costly and more efficient for power tower than for troughs.

There are no commercial power tower plants in operation. The 10 MW Solar One plant near Barstow, California, operated from 1982 to 1988, producing over 38 million kilowatt-hours (kWh) of electricity. Solar One generated steam directly in the receiver. To implement improved heat transfer and thermal storage, the plat was retrofitted (and renamed Solar Two). Solar Two operated from 1998 to 1999. Although Solar Two successfully demonstrated efficient collection of solar energy and dispatch of electricity, including the ability to routinely produce electricity during cloudy weather and at night, the plant encountered various technical issues. Solutions to these issues have been identified; however, successful demonstration of certain improvements is required prior to commercial financing of a large-scale plant.

In addition to Solar One and Solar Two, experimental and prototype systems have operated in Spain, France, and Israel. Solucar Energia, S.A., an Abengoa company, recently announced a 11-megawatt solar power tower near Seville. Called PS 10, the power plant will be the largest solar power system in Europe and the first tower-based solar power system to generate electricity commercially. In addition, ESKOM, the large utility in South Africa, is considering a 100 MW molten-salt plant. A 17 MW molten salt plant in Spain, Solar Tres, was in planning by Ghersa, Boeing, and Nexant. However, this plant appears to be unlikely at this time.

Potential component suppliers include heliostat supplier Sener and Inabensa in Spain. The Rocketdyne Unit of Boeing provided the molten salt receiver for Solar Two, and has been positioned to provide all molten salt equipment (receiver, thermal storage, steam generator) for a new power tower plant. Boeing recently announced the sale of the Rocketdyne Unit to Pratt & Whitney. The long term impact of this sale on solar equipment supply is not known.

Cooling water requirements are about 2.8 m^3/h per MWh, which include a small amount for heliostat washing. Dry cooling reduces this water consumption drastically, although, as with the trough system, performance is reduced and cost increased.

As with the trough system, level land is preferable, with less than 1 percent slope desirable. The land area must be one continuous parcel with essentially a circular footprint.

A.4 CPV Systems

Concentrating photovoltaic (CPV) systems have potential for cost reduction compared with conventional, non-concentrating (also referred to as flat plate) PV systems in two key ways. First, a major portion of conventional PV system cost is for the semiconductor material which makes up the PV modules. By concentrating sunlight onto a small cell, the amount of semiconductor can be reduced, albeit at additional cost for mirrors or lenses and for tracking equipment. Second, use of smaller cells allows for more advanced and efficient cell technology, making the overall system efficiency higher than for a conventional flat plate system.

CPV systems have been under development since the 1970's. This development has included single axis tracking, line focus CPV and two axis tracking, point focus CPV. Recent development has primarily been on the two-axis tracking systems. There are two primary developers of CVP systems today: Amonix, a company based in Torrance, California, and Solar Systems Pty, Ltd, located in Australia.

The Amonix CPV unit, shown on Figure A-7, produces 25 to 35 kW per tracker, depending on how many modules are installed on the tracker. The Amonix system uses hundreds of acrylic Fresnel lenses to focus DNI on high concentration PV cells. Heat rejection is passive, meaning there is no water requirement and no closed loop radiator system The Amonix unit currently has an average annual efficiency of 15.5 percent.

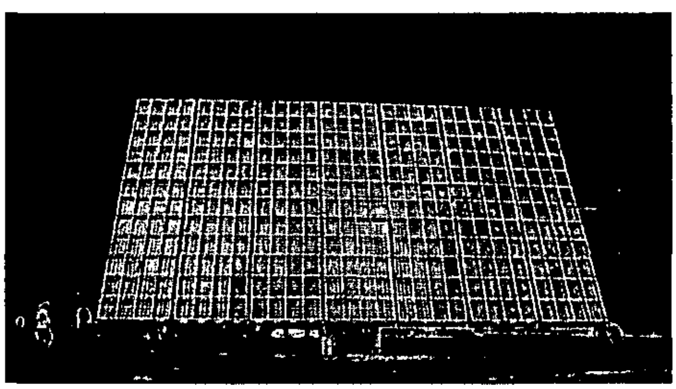

Figure A-7
Amonix: Flat Acrylic Lens Concentrator with Silicon Cells
(Source: NREL)

Amonix systems have been deployed at Arizona Public Service (APS) facilities for a total capacity of 547 kW. Planned deployments in the near future include 10 to 20 MW in Spain. Currently, the systems use high-efficiency silicon cells. Efficiency and capacity gains are expected with advance triple-junction cells and higher concentration.

Solar Systems Pty, Ltd, has a different approach to CPV, using a parabolic dish concentrator to focus DNI on a high concentration PV receiver. This 24 kW system, shown on Figure A-8, averages about 15 to 16 percent efficiency. Ten dishes have been deployed since 2003, for a total capacity of 220 kW, with the construction of an additional 720 kW under way. Several MW of contracts are anticipated in the relatively near future. The next generation of higher efficiency CPV modules is expected to increase the capacity to 35 kW in 2005. The core CPV technology, which accounts for about 25 percent of the cost, would be manufactured in Australia, with the remainder to be manufactured in the United States for a California deployment.

A 50 MW CPV plant would consist of 2,000 25 kW units or 1,430 35 kW units. Similar to the dish-Stirling systems, no cooling water is required for operation. CPV systems have an annual capacity factor of about 26 percent. Near-term R&D is focused on reliability validation, module cost reduction (packaging), and advanced cell technology, e.g., III-V multijunction technology. Similar to the dish systems, level land is preferable for construction and maintenance ease, although it is likely a less significant requirement for CPV sites than that required by trough and tower systems.

Figure A-8
Solar Systems Pty, Ltd: Parabolic Dish PV Concentrator
(Source: NREL)

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This study provides a summary assessment of concentrating solar power and its potential economic return, energy supply impact, and environmental benefits for the State of California.

15. SUBJECT TERMS
Solar power tower; concentrating photovoltaics; concentrating PV; Dish engine systems; Dish Stirling; concentrating solar power; solar parabolic trough; solar trough; parabolic trough

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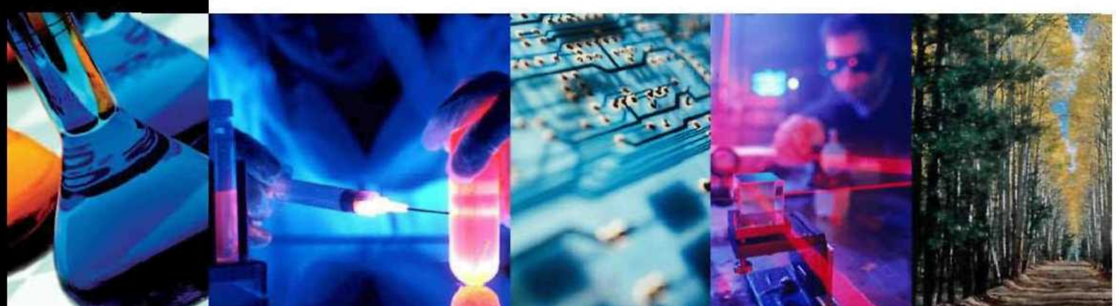
Attachment 2 is voluminous and available for inspection at HECO's Regulatory Affairs Division office, Suite 1301, Central Pacific Plaza, 220 South King Street, Honolulu, Hawaii. Please contact Dean Matsuura at 543-4622 to make arrangements to inspect the document. An electronic copy of the requested information is being provided.

Arizona Solar Electric Roadmap Study

Full Report

January 2007



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Arizona Solar Electric Roadmap

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Peer reviewed by the Arizona Department of Commerce Economic Research Advisory Committee:

This report was prepared for the Arizona Department of Commerce with funding from the Commerce and Economic Development Commission. Elements of this report may be presented independently elsewhere at the author's discretion. This report will be available on the Internet for an indefinite length of time at http://www.azcommerce.com. Inquiries should be directed to the Office of Economic Information and Research, Arizona Department of Commerce, (602) 771-1161.

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Table of Contents

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The Arizona Department of Commerce (ADOC) has the legislated responsibility to develop a 10 year economic plan for the State of AZ.

Project Background

In its role as Arizona's strategic economic research and initiatives entity, the Commerce and Economic Development Commission (CEDC) commissioned this project to help inform the strategy for future business development in the solar industry. Solar (along with water and sustainable manufacturing) was identified in the 2004 "Sustainable Systems Prospectus" as an "economy defining" industry opportunity for AZ based on the R&D strengths of its university system and building on its presence as one of three solar labs in the world.

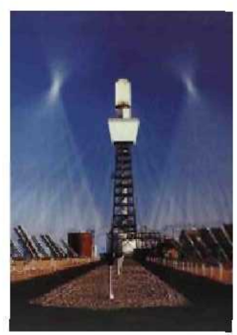
Several international solar energy companies have recently expressed interest in AZ due to the number of days of sunshine and the existing solar electric infrastructure. AZ has the potential to become a world leader in many aspects of solar development, and is a model location for the evolution of new solar technologies and applications. This roadmap is intended to provide a framework to make AZ a world leader in the research, development, manufacture and deployment of next generation solar electric technologies.

AZ wants to accelerate solar adoption, and develop a solar electric industry within AZ that would provide economic development.

Roadmap Goals

- Accelerate the use and adoption of solar technologies in the market and applications to increase energy self-reliance, enhance energy security and protect the environment in Arizona.
- Describe the conditions that could enable Arizona to move toward a leadership position in the research, development, manufacturing and deployment of solar technology by adopting the recommendations and potentially designing a series of demonstration activities.





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PUC-IR-304
DOCKET NO. 2008-0273
ATTACHMENT 2
PAGE 6 OF 189

There are three main objectives of the overall solar roadmap project.

Project Objectives

1. Describe the necessary conditions for the solar electric industry to make investments in Arizona that will result in widespread solar electric deployment of:
   - centralized generation, distributed generation, building practices, local infrastructure support, workforce development, manufacturing and research
2. Describe and recommend the environmental conditions and policy options that will assist Arizona in choosing the optimal portfolio of solar electric energy options
3. Review the potential to increase jobs in solar energy

There are significant incentives available for solar at both the Federal and state level that can be leveraged to help stimulate solar adoption.

Key Federal Policy Incentives for Solar

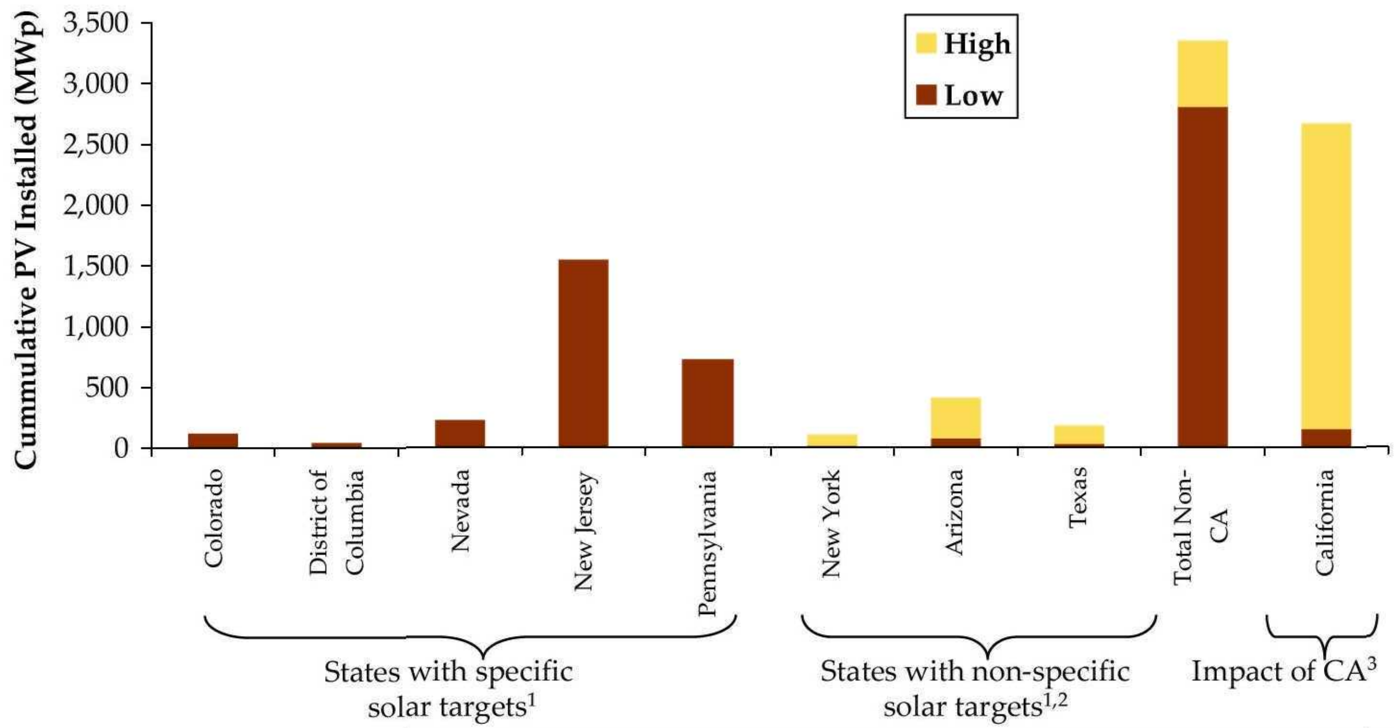
- Solar is often provided incentives compared to other renewable options. EPACT 2005 provides a 30% Investment Tax Credit for commercial installations through 2007 that will revert back to 10% at the end of 2007, unless it is extended.
  - There is also a residential tax credit of 30% (with a maximum cap of $2,000)
- For commercial installations, there is also the 5 year accelerated depreciation
- As of May 2006, the Solar America Initiative (SAI) has been funded $148 million at the President's request.

Key State and Tribe Policy Incentives for Solar

- As of June 2006, 20 states plus DC have renewable portfolio standards (8 with solar or non-wind set asides), and two additional states have renewable goals.
- Tribes are eligible for incentives from a variety of sources and are trying to leverage Renewable Energy Certificates (RECS) as well.
- CA Million Solar Roofs Bill became law in August 2006 providing significant solar incentives for solar development in CA.

RPS demand from solar set asides could result in 3,000 - 3,500 megawatts (MW) of solar without CA, and up to 6,200 MW with CA by 2020.

Estimated Solar Set Aside Capacity Targets by 2020 (MW)



Source: Navigant Consulting Analysis, 2006

1. States have either specific solar targets as a % of generation or MW, or solar can be part of a non-wind set-aside or a DG set-aside. 2. Solar assumed to capture the following % of the state's RPS target: 0.2%-1.0% for NY, 1%-5% for TX, 3%-15% for AZ. For AZ, the 15% RPS target is assumed to have passed. 3.Lower bound for CA assumes installations stall at the 2005 installed capacity level. Upper bound assumes latest CA solar initiative is met.

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Arizona incentives for solar are mostly provided by the utilities.

Key AZ Utility Solar Incentives		
Utility Incentive	**Incentive Amount**	**Comments**
APS Solar Partners Incentive Program **(PV and SHW)**	• $3/W for residential and $2.50/W for commercial grid connected • $2/W for off-grid <5 kW • $.50/kWh for SHW	• Total cap per customer per year is $500,000 • $8.5 million total available for 2006
SRP EarthWise Solar Energy **(PV and SHW)**	• $3/W for residential and commercial PV up to 10 kW • As of July 5, 2006 the incentive level will be $2.50/W for PV systems >10 kW • $.50/kWh for SHW	• Maximum size for PV residential is 10 kW • Maximum amount of credit is $30,000 for residential and $500,000 for commercial
TEP SunShare PV BuyDown	• $2/Wpac Option 1 customer purchase • $2/Wpac Option 2 if purchased from TEP • $2.4/Wpdc Option 3 if customer purchased and operational within 180 days after receipt of agreement	
UES SunShare PV BuyDown	• $2.4/Wpdc for 1 – 5 kW if installed in 2006 for residential and commercial systems	• Incentives available for up to 50 kW of solar per year
Net Metering	• 10 kW for SRP • 10 kW for TEP (500 kW in aggregate)	

The regulated utilities are currently discussing a uniform credit purchase program for solar through the ACC.

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Some additional incentives are available at the state level.

Additional AZ State Level Solar Incentives and Other Related Programs		
Arizona Incentive	**Incentive Amount**	**Comments**
State Income Tax Credit	• 25% up to $1,000	• For residential only • Applies to all solar technologies (PV, SHW, and CSP)
Sales Tax Exemption	• Full sales tax exemption for solar energy systems	• Part of the recent HB2429 bill
Commercial Tax Credit	• 10% commercial tax credit capped at $25,000 per system and $50,000 per company annually	• Program capped at $1 million. Part of the recent HB2429 bill
AZ Enterprise Zone	• $3,000 for each net-new qualified employee over a 3-year period for a maximum of 200 employees in any given tax year. • A reduction of assessment ratio from 25% to 5% of all personal and real property for primary tax purposes for 5 years	• An effort to improve economies of designated areas in AZ by enhancing opportunities for private investment.
Property Tax Exemption	• Full property tax exemption for property owners installing solar energy systems	• Part of the recent HB2429 bill
Interconnection	• ACC is developing a statewide interconnection standard, but this is still in progress	
Job Training Program	• Provides grant money to companies creating full time permanent new jobs or training for existing worker within AZ	
AZ Workforce Connection	• Provides free services to employers who seek access to skilled new hires or existing worker training resources	

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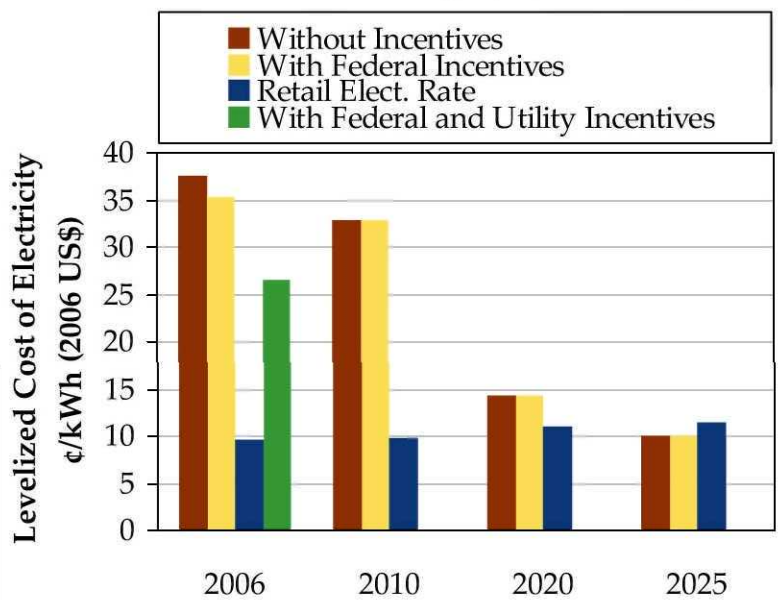
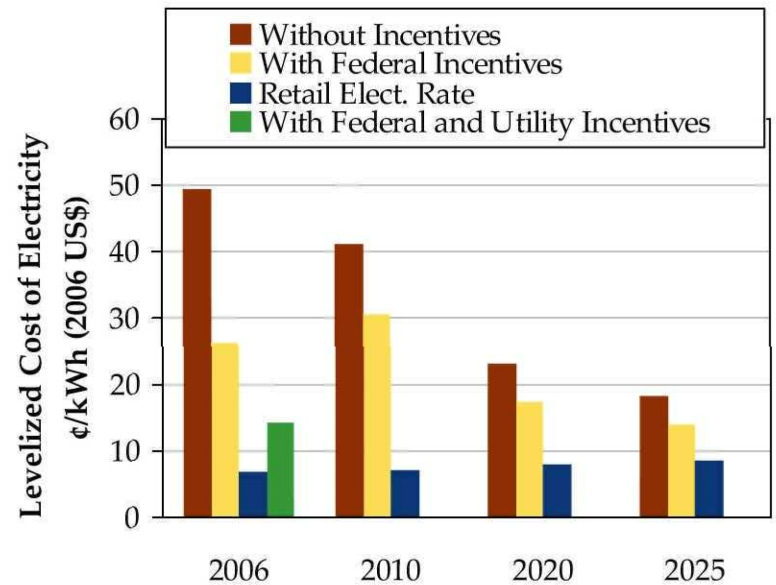
Currently, customer sited PV is more expensive than retail electricity, but future expected cost reductions will close the cost gap.

AZ Levelized Cost of Electricity for Residential and Commercial PV

Residential Rooftop (2.5 – 3kW)



Commercial Rooftop (50 – 300 kW)



Key residential assumptions without incentives: 100% debt, cost of debt = 6.25%, Insurance = 0.5%, Loan period = 10 years. Project economic life (for property tax calculations) = 25 years. Property tax rate of $11.70/$100 of assessed value. Electricity cost of .095$/kWh growing at 1%/yr. Key commercial assumptions (without incentives): Debt equity ratio: 55%:45%, cost of equity = 15%, cost of debt = 8%, Marginal federal + state income tax = 41%. Insurance = 0.5%, Depreciation under Modified Accelerated Cost Recovery System (MACRS): Depreciation period considered is 15 years. Loan period = 10 years. Project economic life (for property tax calculations) = 25 years. Property tax rate of $11.70/$100 of assessed value. Electricity cost of $.07/kWh growing at the rate of inflation. Retail elect. rates assume constant (real) 2006 dollars and a 1%/yr real increase through 2025. See more detailed discussion in Section 3 for with incentive assumptions. Note: The LCOE for residential is lower than for commercial building installations primarily as a result of cost of capital assumptions.

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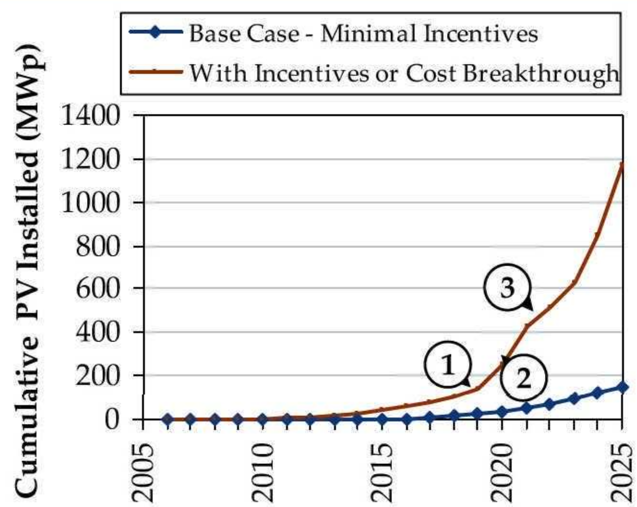
PUC-IR-304
DOCKET NO. 2008-0273
ATTACHMENT 2
PAGE 13 OF 189

With significant subsidies or cost breakthroughs, cumulative installations of rooftop PV by 2020 can be substantial.

AZ Rooftop PV Market Penetration (Residential + Commercial)



- Significant market penetration does not begin until payback rates drop below 10 years. This occurs in 2020 in the incentive/breakthrough case
- Installed PV could increase more rapidly after 2025 if prices relative to the grid continue to drop

Source: Navigant Consulting, Inc. analysis, September 2006.

Key Market Dynamics

1. Installations cross a tipping point as the payback period drops below 10 years. However, not all customers adopt immediately. Current payback levels are 35 years for commercial and 32 years for residential, with incentives.
2. Installations accelerate as 1) the payback period decreases – causing more customers to want to buy PV systems, and 2) time passes and adoption increases (the slow adopters actually adopt).
3. Installations decelerate slightly as the slow adopters have already adopted, and new installations are driven primarily by those who have waited for the price to continue to come down.

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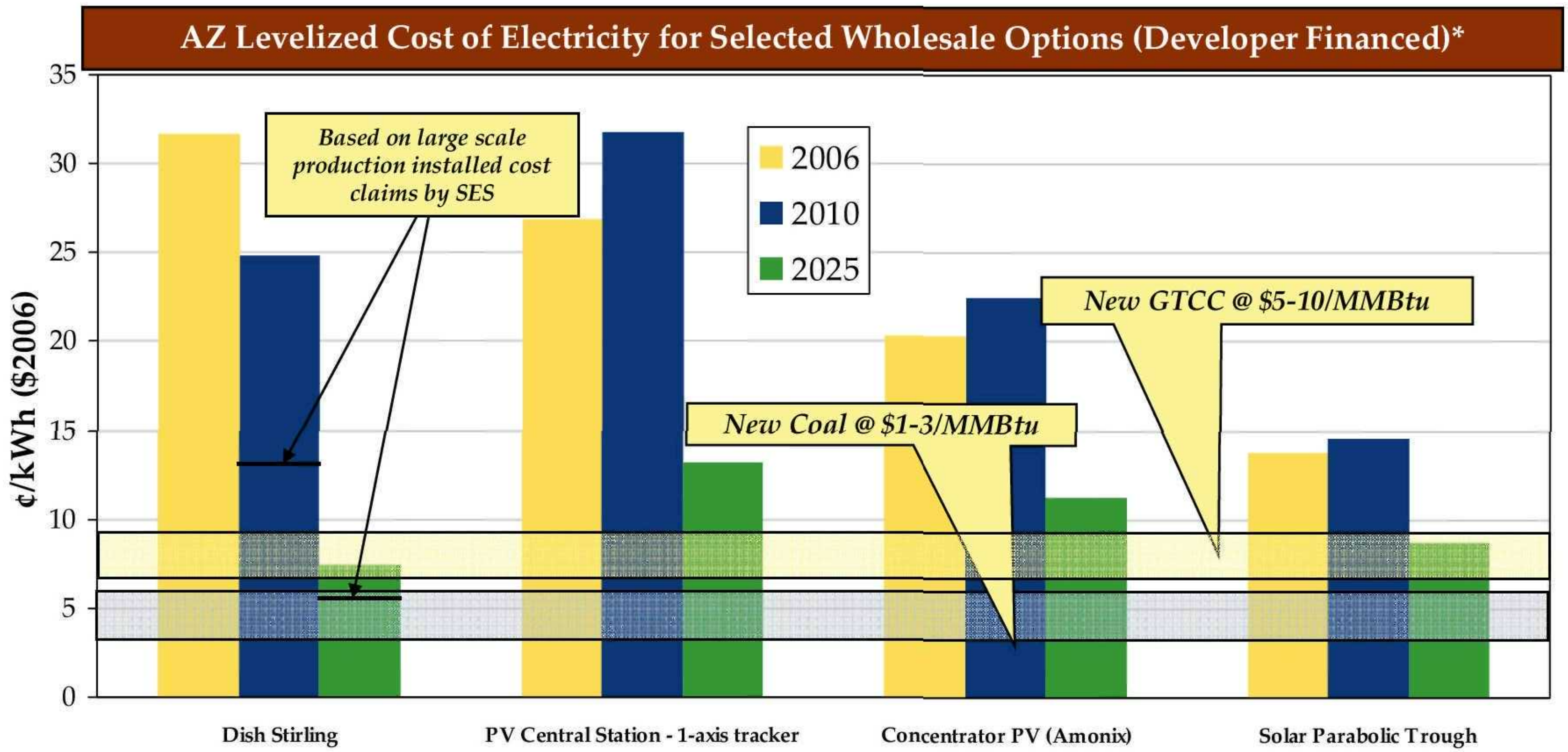
Technology improvements/cost reductions will allow central solar to compete with conventional baseload and intermediate generation.



Note: All cost estimates exclude additional revenue from renewable energy certificates. New Coal will generate electricity at 3.7 to 5.6 cents/kWh and new Gas Turbine Combined Cycle (GTCC) at 5.7 to 9.2 cents/kWh. *LCOE includes 10% ITC and accelerated depreciation, and 30% ITC for 2006. NCI analysis using data from NREL in 2006 and Bob Liden, Executive VP and General Manager, Stirling Energy Systems, for Dish Stirling, September 19, 2006.

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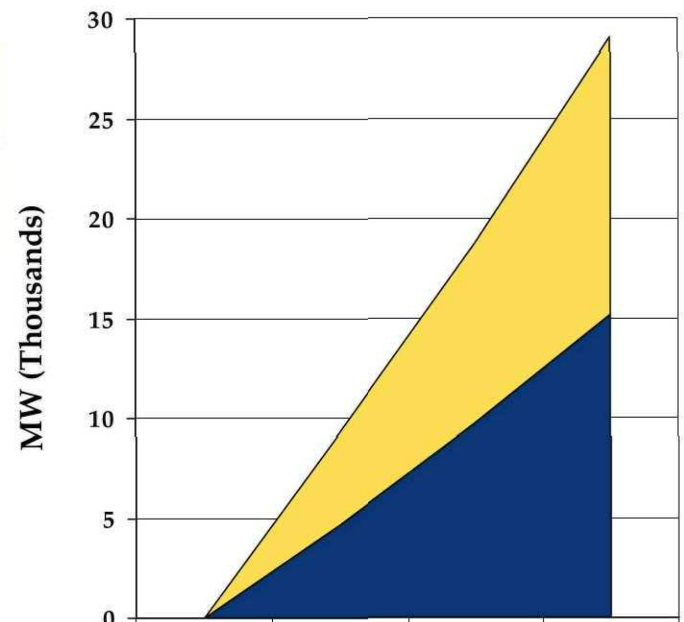
Peak loads in the desert southwest states and California are forecasted to grow by nearly 2,000 MW per year for the next 15 years.

NERC Sub-Region	Expected Peak Load (MW) 2005-2020			
	2005	2010	2015	2020
AZ, NM, South NV	26,972	31,624	35,972	40,897
CA	57,324	61,985	67,031	72,492
Total	84,296	93,609	103,003	113,389

Peak growth in the desert southwest is forecasted to be nearly the same as CA.

Peak Load Growth (MW)



	2005	2010	2015	2020
AZ, NM, & So NV	0	4,652	9,000	13,925
California	0	4,661	9,707	15,169

Source: WECC, CA Energy Commission, NCI Analysis

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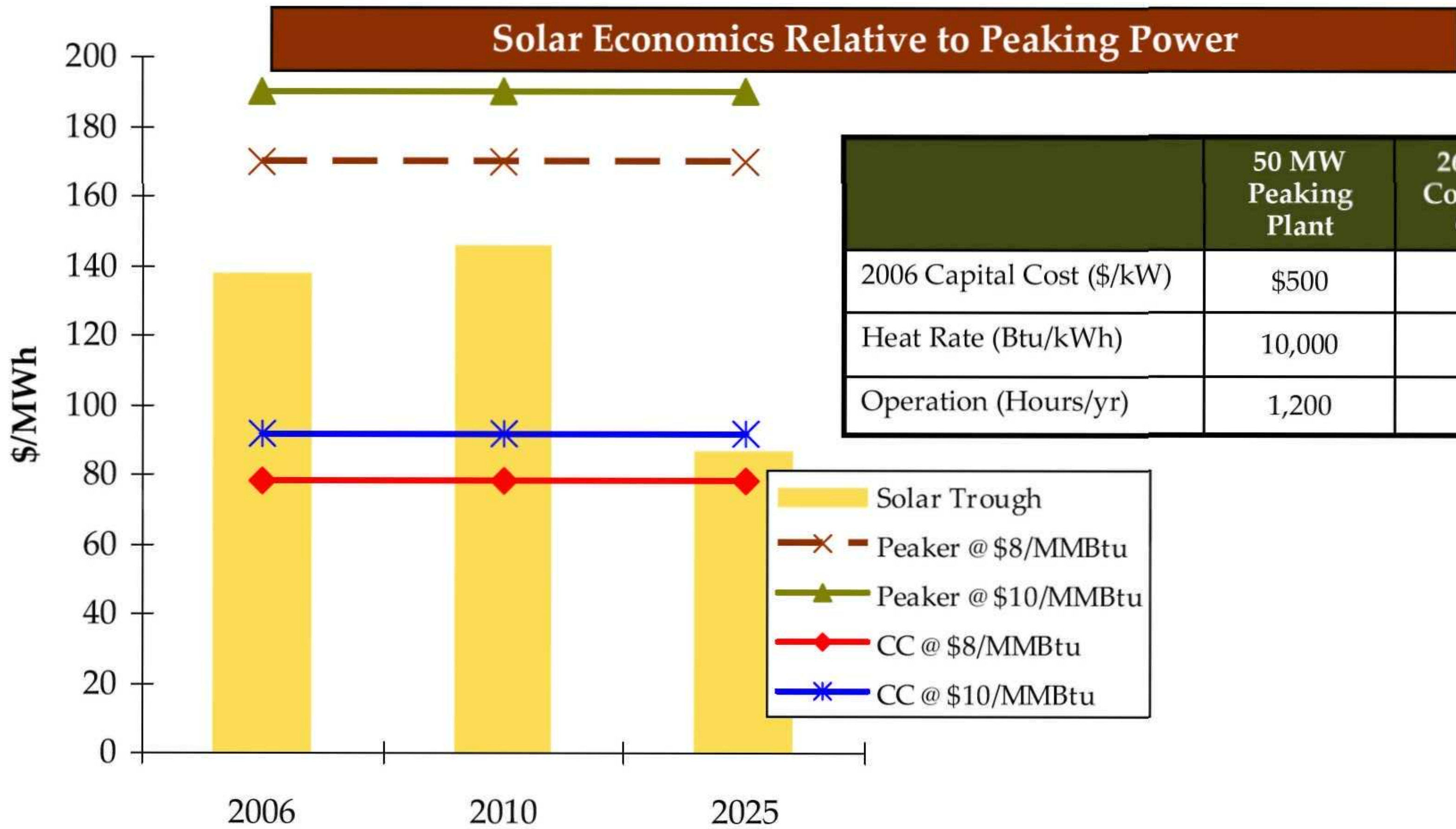
Cost of electricity from parabolic trough is near the cost of peaking power today, with costs expected to decline by more than 50% by 2025.



	50 MW Peaking Plant	260 MW Combined Cycle
2006 Capital Cost ($/kW)	$500	$650
Heat Rate (Btu/kWh)	10,000	7,200
Operation (Hours/yr)	1,200	7,500

Note: LCOE for solar includes Federal Investment tax credit, and accelerated depreciation. 2010 and 2025 assumes 6 hours of storage.

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However, the cost of electricity of solar is not directly comparable to the cost of electricity of peakers or combined cycle plants.

Discount Factors for Gas

- Solar output is comparable to a mix of peaker and combined cycle
- Peaker capacity has added flexibility to generate when needed
- Peaker capacity may still be required to address:
  - Intermittency
  - Non-coincidence of system and solar peak

Discount Factors for Solar

- Hedge value against gas price volatility
- Impact of lower gas usage upon average gas prices
- Value/compliance costs for emissions reduction
- Six hour storage capability built into post 2010 costs mitigate intermittency and non-coincidence issues

Two scenarios were developed for deployment of central station solar power through 2020.

	Base Case	Accelerated
Key Assumptions	• Business as usual • Central solar costs decline, but no breakthrough • Average gas prices remain in the \$7.00 to \$8.00/MMBtu range • Siting and transmission issues result in minimal export capability • Solar trough has 6 hour storage after 2010	• Early central station solar technology projects perform as planned, and costs decline as forecast • Average gas prices in the \$9.00 to \$10.00/MMBtu range • Greenhouse gas and other emissions add \$5/MWh to combined cycle costs • Transmission capability developed by 2020 to support an additional 200 MW of exports
Through 2015	Only modest deployment of central station solar in AZ under both scenarios, driven primarily by the state's RES	
Post 2015	• Central station solar continues modest deployment driven by RES	• Central solar captures 20% of the AZ capacity additions

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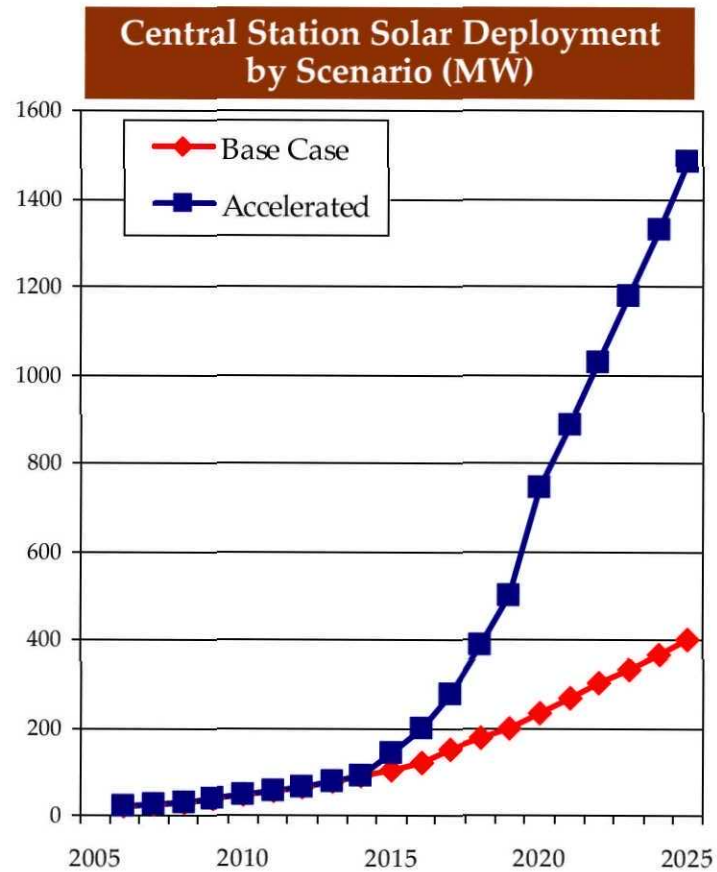
In the breakthrough scenario, central station solar deployment expands dramatically after 2015.

- Through 2015, central solar captures about 10% of the RES requirements in both scenarios
- For the Base Case, central solar continues to capture about 10% of the RES applied on a state-wide basis (~ 400 MW by 2025)
- In the Accelerated scenario about 10% of 2015 capacity are central solar, ramping up to 20% of capacity additions by 2020. In addition, slightly more than 20 MW is developed for export annually



Source: Navigant Consulting, Inc. estimates, 2006.

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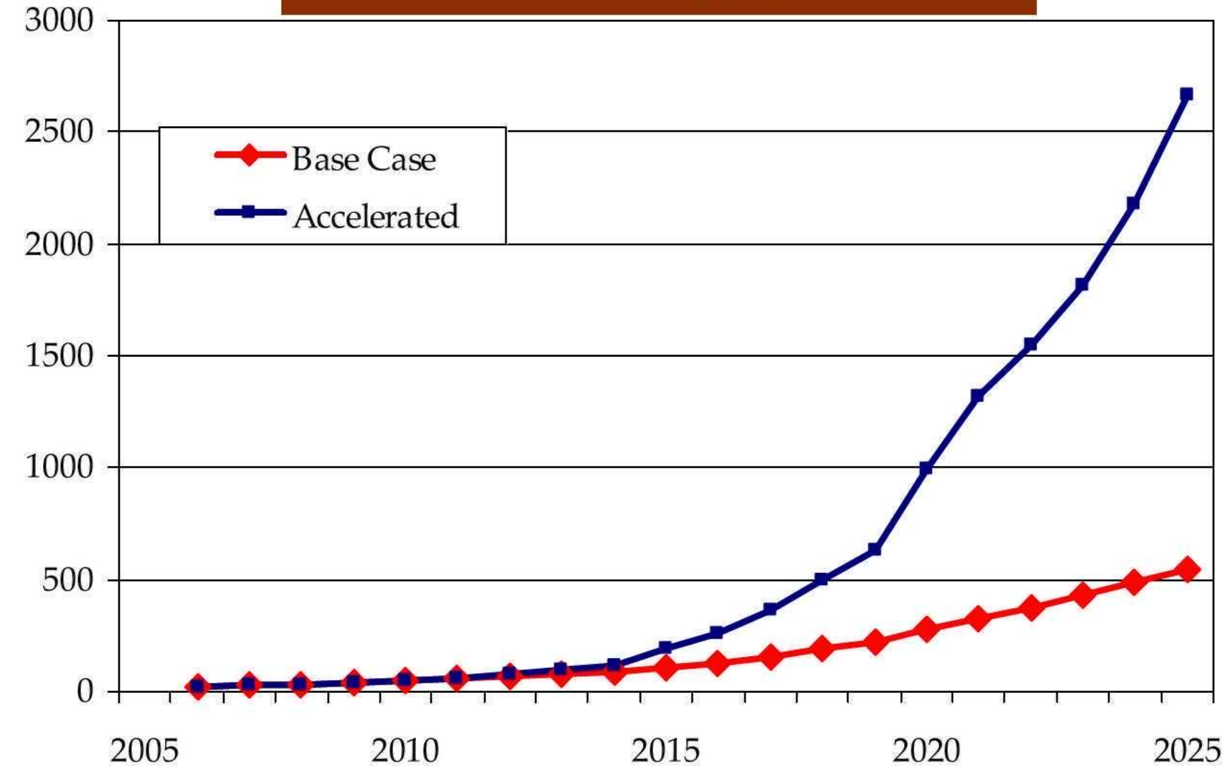
PUC-IR-304
DOCKET NO. 2008-0273
ATTACHMENT 2
PAGE 19 OF 189

Total solar deployment could exceed 2,600 MW in the accelerated scenario with rooftop PV accounting for about 45% of the capacity.

Total Solar Electric Deployment (MW)



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The accelerated scenario for solar could add over 3,000 jobs in 2020.

Accelerated Scenario In 2020	Cumulative Capacity (MW)	Installations in 2020 (MW/yr)	Direct Manufact. (# Jobs*)	Installation/ Construction (# Jobs)	O&M (# Jobs)	Installation Labor Expenditure (Million $)	O&M Labor Expenditure (Million $)
Rooftop PV	250	115	450	1,800	75	243	4
Central Solar	742	143	60	429	233	54	26
TOTAL	992	258	510	2,229	308	297	30

*Assumes none of central solar components are manufactured in AZ, except for PV where 20 MW were assumed to be manufactured in state. Assumes that an additional 150 MW plant is in AZ for the rooftop PV market (some in state and some exported).

Source: Navigant Consulting, Inc. estimates, June 2006.

Total 2020 employment = 3,047 jobs for solar in an accelerated scenario

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Emission reduction is estimated at 400,000 tons per year in an accelerated scenario in 2020.

Emission Reduction Potential in AZ (Accelerated Scenario in 2020)				
Accelerated Scenario	Cumulative Capacity (MW)	Average Capacity Factor (%)	Energy Delivered (MWh)	Total CO_2 Reduction (Tons)
Rooftop PV	**250**		**388,075**	**60,000**
• Residential	187	18.3%	299,775	
• Commercial	63	16%	88,300	
Central Solar**	**742**		**2,182,500**	**338,200**
• Trough	519	38%	1,728,000	267,800
• Dish Stirling	148	23%	299,000	46,300
• PV	37	25%	81,000	12,600
• Concentrating PV	37	23%	74,500	11,500
TOTAL	992	26.3%	2,570,575	**398,200**

*Assumes .31 lbs/kWh of CO2 are displaced for a Combined Cycle Gas Turbine in 2020.
** Assuming market shares of: 70% trough, 20% dish Stirling, 5% concentrating PV, and 5% flat plate PV based on economics.

Source: Navigant Consulting, Inc. estimates, August 2006.

There are many unique attributes in AZ that were identified in the interviews that were incorporated into the roadmap.

AZ Uniqueness & Strengths

- AZ Corporation Commission proactive leadership on its Renewable Energy Portfolio Standard
- AZ population and economic growth
- The excellent solar resource (high direct and diffuse solar radiation which is excellent for concentrating and flat plate PV)
- AZ high dependence on gas and its volatile price
- The ideal and central location of AZ to key nearby solar markets (TX, CA, NV, CO, NM)
- State Trust Lands and tribal lands could be used for large scale solar developments
- Competitive labor costs and tax rates
- ASU Poly PV certification capability is only one of three in the world (other 2 are in Northern Italy and Germany)
- ASU hosts the Power Systems Engineering Research Center, a consortium of 13 universities and 39 companies which is funded by the National Science Foundation
- Availability of funds close to $1.2 billion from RES through 2025 ($60 million per year)
- ASU assets (e.g. clean room, monitoring and evaluation equipment)
- UA assets (R&D on 3rd generation solar cells, clean rooms and characterization equipment)
- STAR facility for evaluating emerging technologies (only 2 others in world: Weizmann Institute in Israel and Australian National University)

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Several barriers were also identified for large scale development of customer sited and central station solar.

- Capital cost
- Technology immaturity
- Significant solar incentives in other countries
  - Tax holidays (personal and corporate); free land; reduced power rates; access to water and plant cost subsidies of 30 – 45% in locations such as Germany
- Lack of PV educated human capital and infrastructure
- Low utility rates relative to other nearby states
- Lack of local strong market (relative to other some other U.S. states)
- Competition from neighboring states (e.g. NM manufacturing incentives)
- Perception of the need for gas back-up with solar to address intermittency
- Local building codes
- Homeowner associations and restrictions on solar installations

Key Barriers

Many threats were also identified through an interviews process.

- A natural gas price collapse would reduce the competitiveness of solar
- Public concerns about NIMBY, aesthetics etc., may influence and limit the siting and large-scale deployment of central plants
- The planned use of central station or next generation PV systems that have not been fully proven may weaken the initiative
- Sustained economic recession results in concerns about investments in initially more expensive solar options
- Module shortage persists so systems can not be obtained to be installed

Key Threats

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If some barriers can be overcome, there is potential for annual installations > 250 MW/yr in 2020, resulting in close to 3,000 new jobs.

Opportunities

- MWs in 2020 (Accelerated Scenario):
  - Central Solar: 145 per year
  - Rooftop: 115 per year
- Jobs in 2020 (Accelerated Scenario):
  - Direct Manufacturing: 510 per year
  - Installation/Construction + O&M: ~2,535
- Emissions Reductions in 2020 (Accelerated Scenario):
  - Central Solar: ~338,200 Tons of CO_2/Year
  - Rooftop: ~60,000 Tons of CO_2/Year
- Spin-off value of R&D development
- Additional economic development e.g. tourism to visit solar "centers of excellence" and deployment centers
- Enhanced sustainable AZ: maintaining AZ's quality of life

NCI's road-mapping process identified actions/recommendations based on analyses of the market opportunities, competition, and barriers.

Market Opportunity
- Research & Development
- Manufacturing
- Distributed systems deployment
- Central station development & operation

Potential Benefits To Arizona
- Jobs
- Supply security
- Electricity prices and stability
- Reduced emissions
- Image

Arizona Competitive Position
- Strengths
- Weaknesses
- Threats
- Areas of competitive advantages

Barriers
- Financial
- Institutional
- Infrastructure
- Availability
- Wholesale markets
- Transmission
- Siting
- Other

Roadmap & Action Plan

Policy and program recommendations and action items for:
- Near–term
- Mid-term
- Long-term

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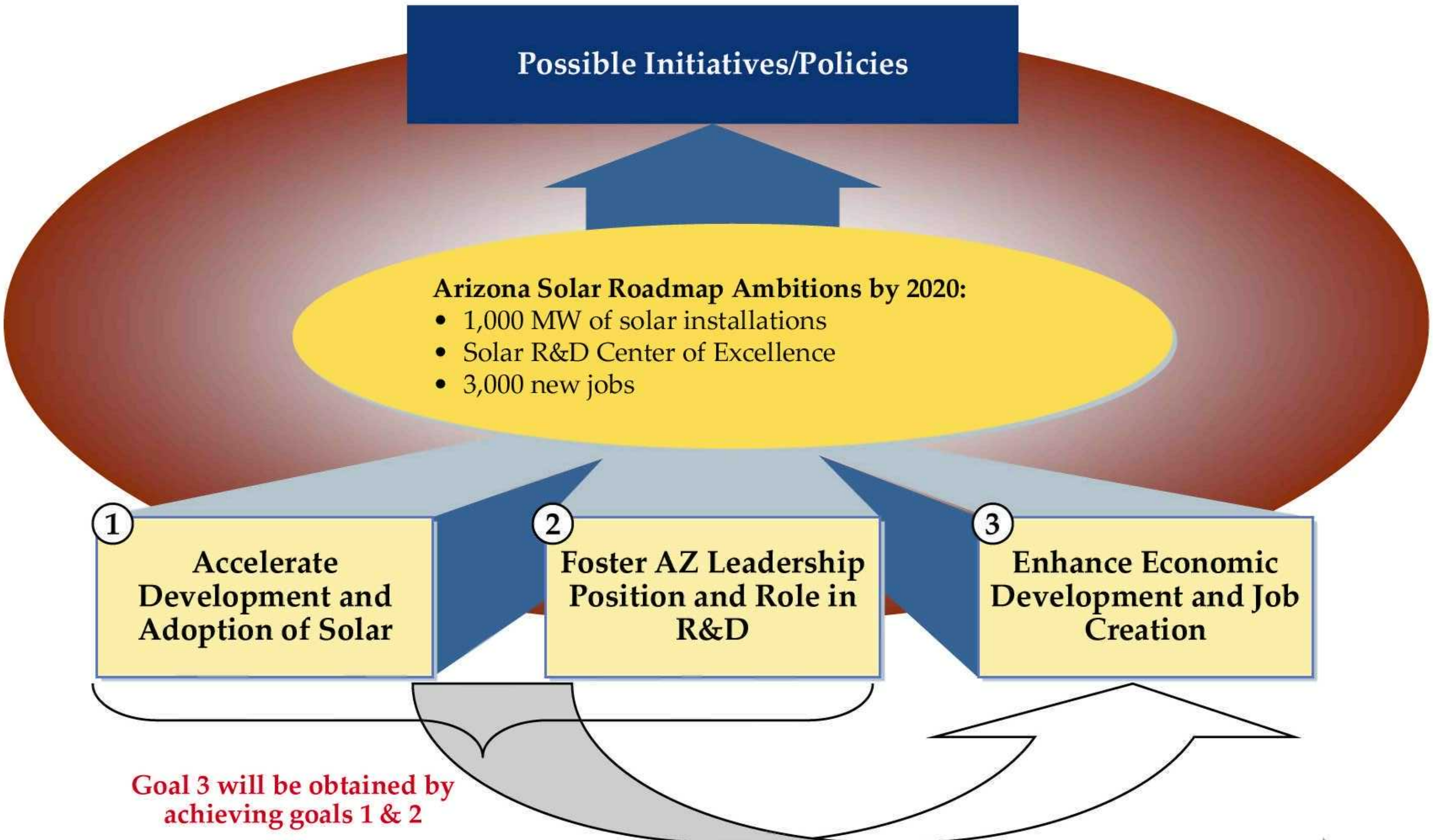
NCI along with the Steering Committee identified initiatives and policies that would address three goals and ambitions.



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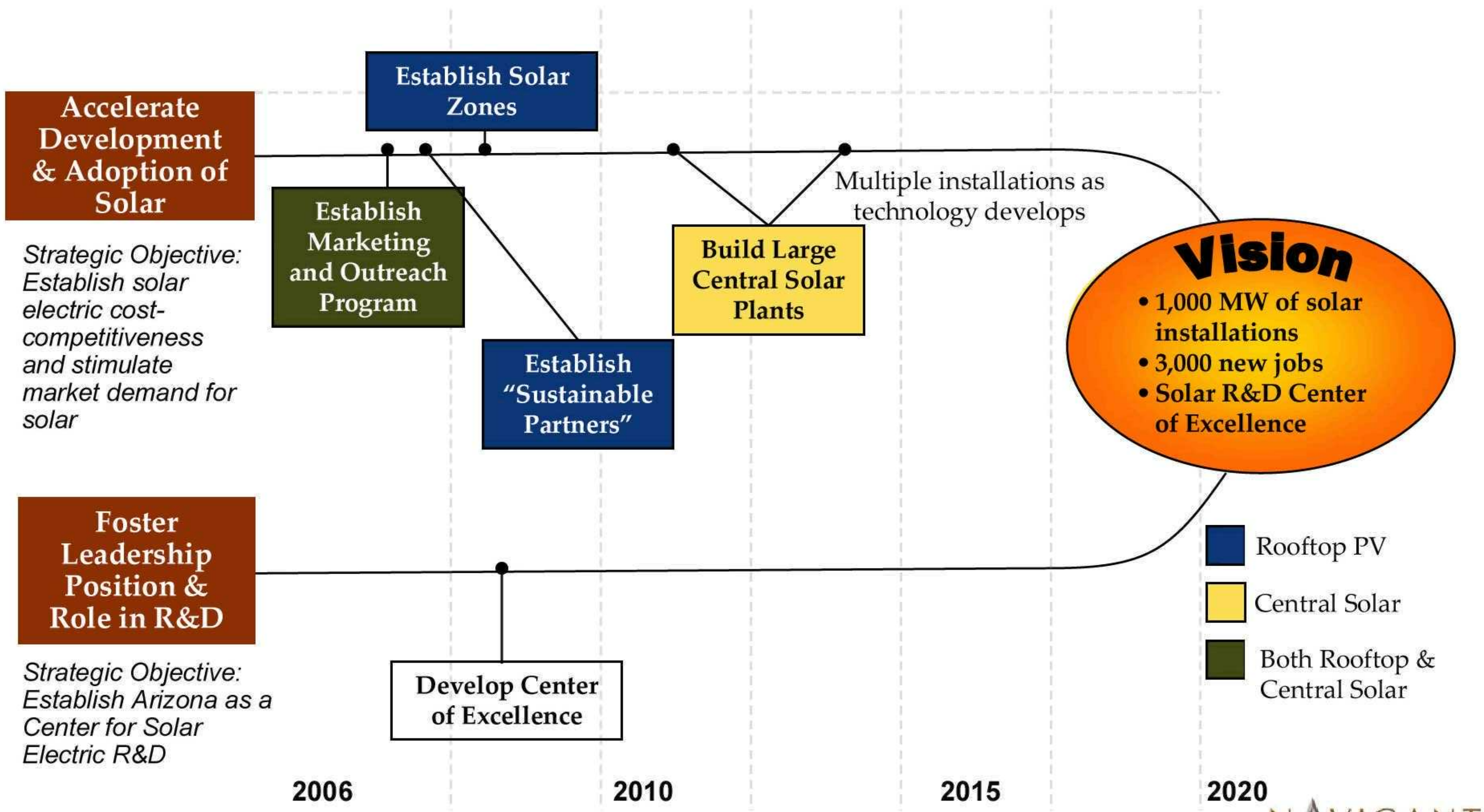
The vision and ambitions are achieved through integrated initiatives that build upon established policies and incentives.



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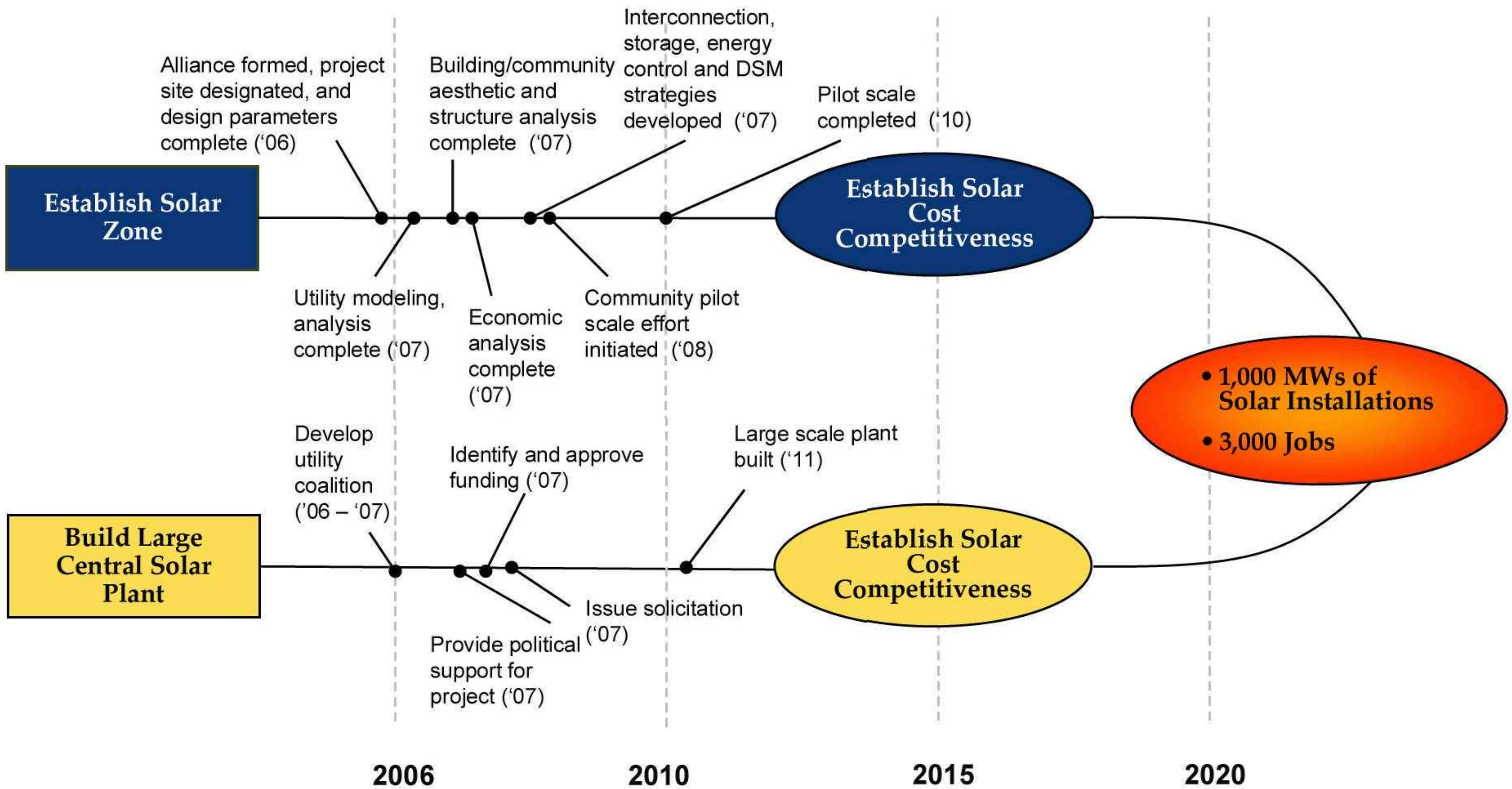
PUC-IR-304
DOCKET NO. 2008-0273
ATTACHMENT 2
PAGE 29 OF 189

Below are key milestones to help accelerate the development and adoption of solar.



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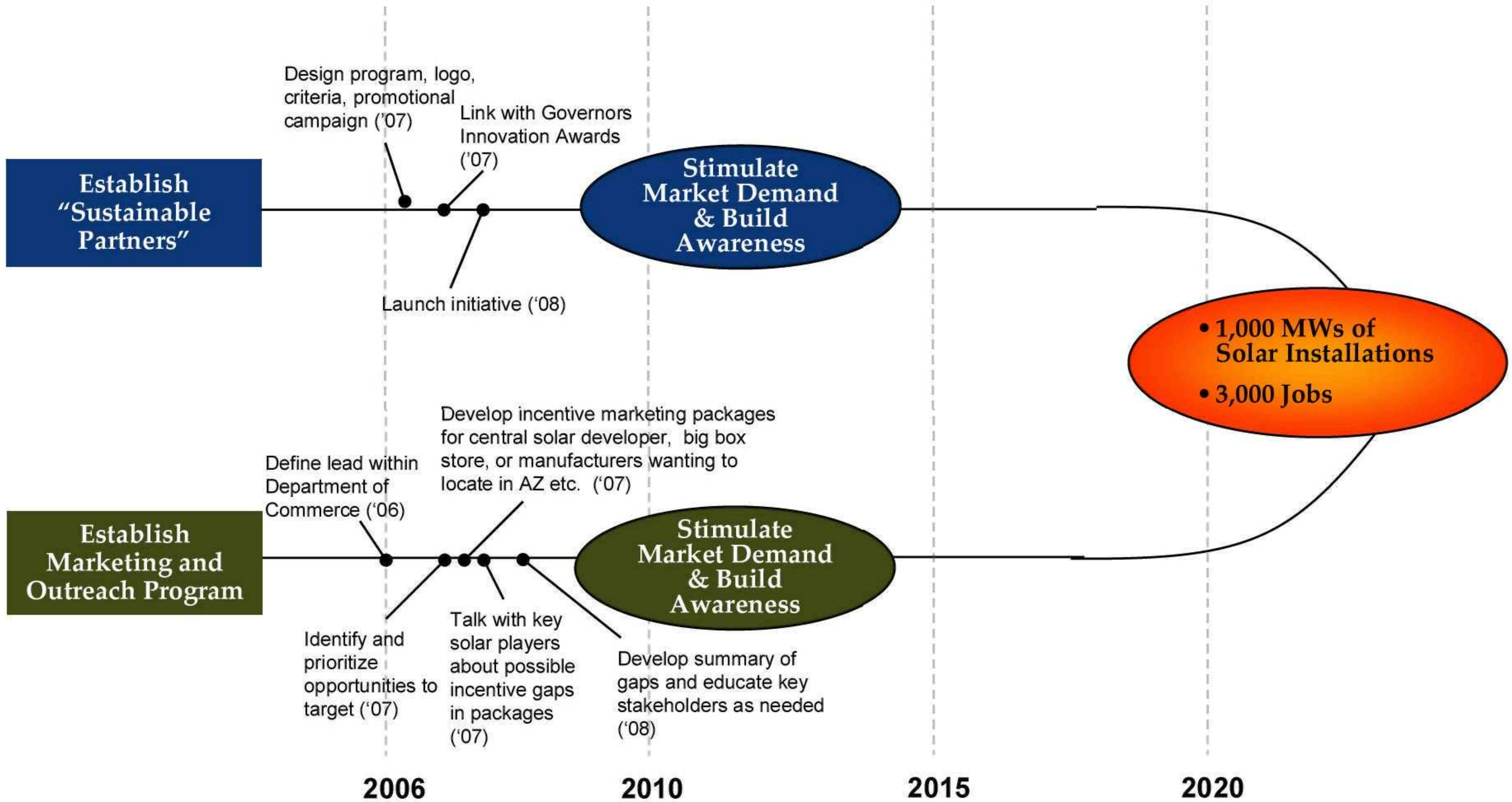
Below are additional key milestones for development and adoption of solar through stimulating market demand and building awareness.



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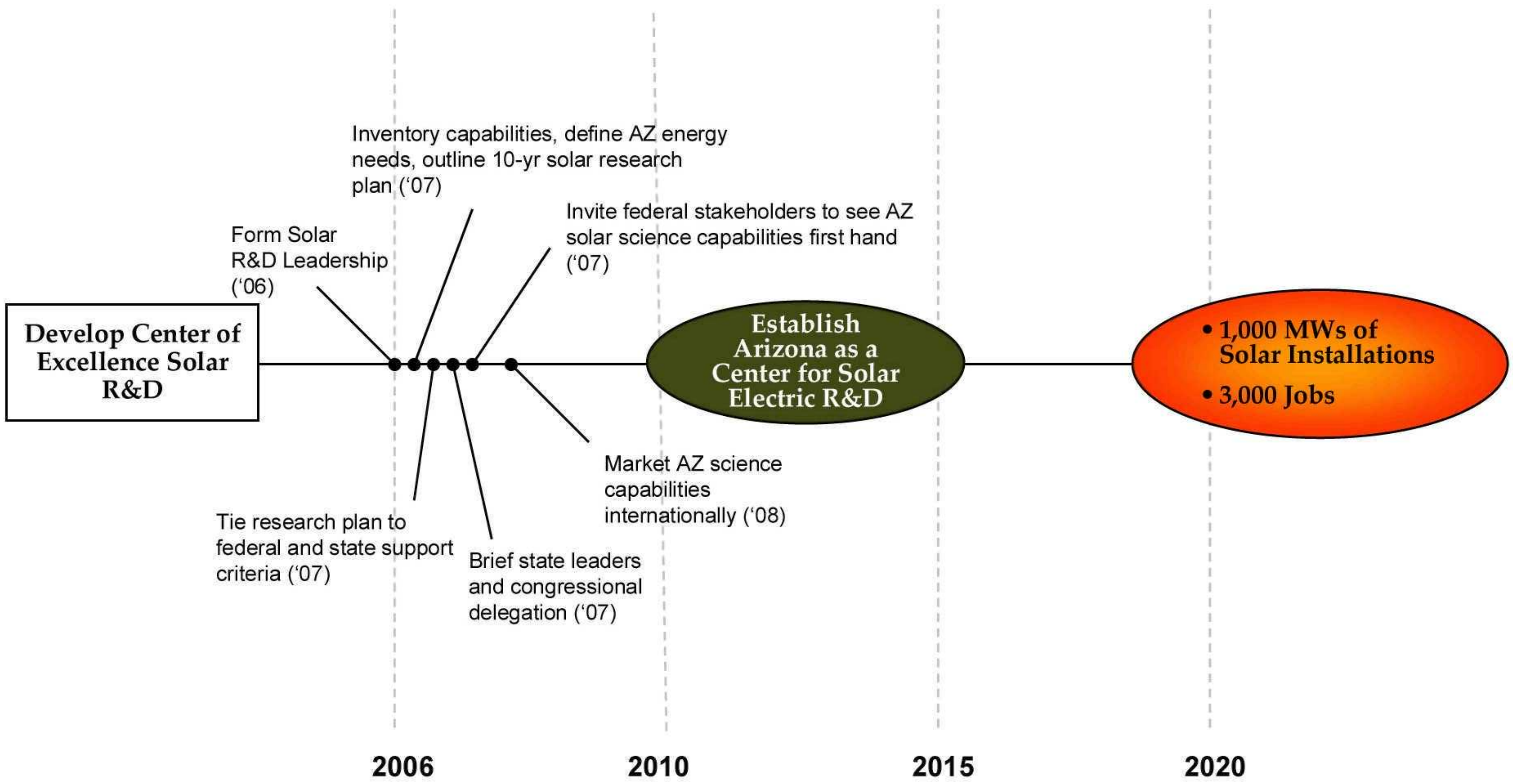
Below are the key milestones for building knowledge to support the development of a Center of Excellence for Solar R&D.



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Implementing the roadmap initiatives will allow AZ to build upon its assets and policies to establish a leadership position in fostering solar.

Arizona Solar Roadmap Ambitions by 2020:

- 1,000 MW of solar installations
- Solar R&D Center of Excellence
- 3,000 new jobs

Roadmap Initiatives

- Establish solar zones
- Build large central station plant (s)
- Establish "Arizona Sustainability Partners"
- Establish marketing & outreach
- Develop Solar Center of Excellence

- RES requirements
- Utility programs
- Tax credits (including sales and property tax exemptions)
- Job training funds

- Best solar resource in nation
- Rapidly growing markets
- Region committed to sustainable development
- Pro-business environment
- Opportunity for Tribal partnerships
- Intellectual capital at post-secondary institutions

Table of Contents

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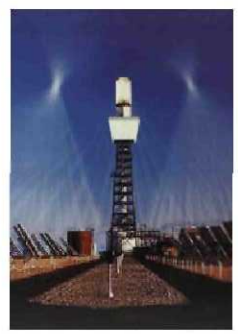
AZ wants to accelerate solar adoption, and develop a solar electric industry within AZ that would provide economic development.

Roadmap Goals

- Accelerate the use and adoption of solar technologies in the market and applications to increase energy self-reliance, enhance energy security and protect the environment in Arizona.
- Describe the conditions that could enable Arizona to move toward a leadership position in the research, development, manufacturing and deployment of solar technology by adopting the recommendations and potentially designing a series of demonstration activities.



There are three main objectives of the overall solar roadmap project.

Project Objectives

1. Describe the necessary conditions for the solar electric industry to make investments in Arizona that will result in widespread solar deployment of:
   - centralized generation, distributed generation, building practices, local infrastructure support, workforce development, manufacturing and research
2. Describe and recommend the environmental conditions and policy options that will assist Arizona in choosing the optimal portfolio of solar electric energy options
3. Review the potential to increase jobs in solar energy

NCI used a six-step approach to help AZ develop a solar electric roadmap.

Policy Strategy

- Attend kick-off meeting in AZ to:
  - introduce NCI team and meet Steering Committee,
  - confirm project scope and deliverables,
  - define appropriate communication channels and frequency, and
  - establish priorities for selecting policies to support the roadmap objectives
- Review existing policy/incentives for solar in AZ and U.S.
  - identify best practices of utility, state, Federal, tribal, and local stakeholders
- Define the best policies to meet the AZ objectives (Task 6 Recommendations)

Technology and Deployment Strategy

- Determine levelized cost of energy (LCOE) for parabolic trough, dish Stirling, concentrator PV, central station flat plate PV, residential rooftop PV, and commercial building rooftop PV for 2006, 2010, 2020 and 2025 without state incentives
  - Use NCI proprietary LCOE model and provide AZ with key technology and performance assumptions
- Identify benefits and challenges for each of the technology options
- Estimate the market potential and market penetration rates for rooftop PV
- Identify centers for expertise and areas of core competency in AZ

Local Barriers

- Conduct 5 – 8 interviews with AZ manufacturers, regulators, utilities, developers, tribes, and other key players to identify barriers to entry/deployment
- Assess significance and likely persistence of the barrier
- Identify and evaluate *options to overcome* significant barriers
- Analyze advantages, disadvantages, and feasibility of overcoming barriers through 5-8 interviews with industry, regulators, utilities, tribes, and government
- Recommend actions and policies to overcome barriers

Existing Business and Industry Status

- Review key utility, industry, investor, and developer solar activity
- Interview 5 – 7 key players to obtain their opinions about local, national, and international opportunities
- Define potential *technology* strategies for each solar technology option

Economic and Market Analysis

- Summarize generation capacity additions of conventional power through 2025 within AZ and WECC under two scenarios
- Synthesize publicly available data on electricity price forecasts and transmission capacity for export of solar
- Provide electricity price forecasts for two scenarios
- Describe WECC vulnerabilities and estimate impact on electricity price forecasts for WECC, California and Arizona
- Review AZ utility resource plans through 2020
- Discuss possible risks and uncertainties in resource plans
- Review solar plans and capacity additions through 2025 (conduct 3 - 5 interviews with staff at APS, TEP, and SRP)
- Estimate solar technology LCOE for 2010 and 2025
- Estimate market potential for solar thermal electric and rooftop PV for 2010 and 2025

Recommend-ations

- Develop roadmap and recommendations from synthesis of previous tasks
- Work with Steering Committee to develop policy objectives and goals, and to refine the recommendations
- Assess AZ competitive position relative to strengths, weaknesses, *and threats*
- Conduct workshop with Steering Committee for roadmap and action plan development
- Provide recommendations for three time frames:
  - near-term (1 – 5 years)
  - medium-term (5 – 10 years)
  - long-term (>10 years)

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NCI used a six-step approach to help AZ develop a solar electric roadmap.

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Table of Contents

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Compared to other renewable technologies, solar is often provided incentives at the national level.

Incentive	Description	Applicability					
		PV	Solar Thermal Electric	Wind Power	Biomass/ LFG	Low-Impact Hydro	Geo-thermal
Production Tax Credit (PTC)	• 1.9 ¢/kWh, after tax, for first 10 years of operation. PTC is indexed to inflation and is good through 12/31/2007. • Full value applies to wind, solar, geothermal and "closed-loop" biomass • Credit value is reduced to 0.9¢/kWh for "open-loop" biomass, small irrigation power/qualified hydro production, cogeneration and waste-to-energy			✓	✓	Small irrigation power only between 150kW and 5MW	✓
Investment tax credit (ITC)*	• 30% of the investment purchase/installation on income tax for commercial installations. Good through 12/31/07, then reduces back to 10%. PV also has a residential tax credit of 30%, but with a cap of $2,000	✓	✓				✓
Accelerated Depreciation	• Eligible technologies are classified under Modified Accelerated Cost Recovery System (MACRS) property class 5, allowing 5-year vs. 15 year depreciation	✓	✓	✓			✓
Renewable Energy Production Incentive (REPI)	• Rough equivalent to the PTC but for municipal utilities and other public entities • 1.50¢/kWh (1993 $) adjusted for inflation for the first 10 years of operation.[1] • EPAct 2005 reauthorized this program through 2026 (i.e., for project installed through 2016) • 60% of available funding to wind, solar, geothermal, biomass or ocean in shortfall years	✓	✓	✓	✓[1]		✓[2]

1. The REPI is subject to annual appropriations such that it may not be fully funded from year to year. 2. Contains restrictions on the type of geothermal reservoir.

*The House and Senate have introduced the Securing America's Energy Independence Act to extend the ITC for solar and fuel cells through 2015.

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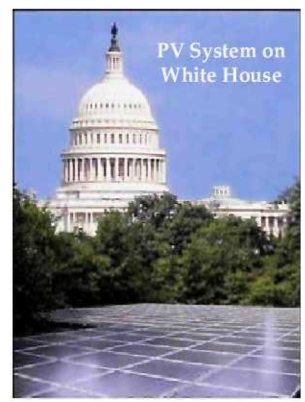
EPACT 2005 provides a 30% ITC for commercial installations of solar through 2007, but this may be extended through 2015.

EPACT 2005

- An increase, through the end of 2007, in the Investment Tax Credit (ITC) for solar, from 10% to 30% of installed cost.
  - Eliminated the $25,000 cap
  - Reverts back to 10% after end of 2007
  - Covers all equipment and installation costs
- Creation of a residential solar tax credit of 30% (with a $2,000 maximum)
- Renewable energy purchase requirements for the Federal sector (reaching 7.5% by 2013, up from 2.5% in 2005). Is likely to result in 150 MW of PV
- A PV commercialization program for the procurement of PV systems for public buildings
- Clean and renewable energy bonds are established, but applications had to be in last April
- Increases solar R&D to $250 million annually
- Electricity provisions: net metering, interconnection standards, and time based rates

Securing America's Energy Independence

- House and Senate Bills both include:
  - Extension of 30% business credit for PV, CSP, and solar hot water until Dec. 31, 2015. Credit can be taken against alternative minimum tax (AMT).
  - Extension of 30% residential tax credit for solar water heating, PV and fuel cells
    - Changes maximum to $2,000 for each kW of solar (vs. flat $2,000 cap) and $1,000 for fuel cells. Credit can be taken against AMT.



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As of May 2006, the Solar America Initiative (SAI) has been funded $148 million at the President's request.

- In May 2006, the House Appropriations Committee approved the FY2007 Energy and Water Appropriations bill
- Total funding for the DOE Solar Program was $148.3 million
  - $134.3 million for PV
  - $8.9 million for CSP
  - $5 million for solar heating and lighting
- The Office of Science has additional funds for solar R&D
- Currently undertaking Technology Acceptance exchange meetings to obtain inputs to the SAI
  - The mission of SAI is to achieve cost-competitiveness of solar energy technologies by 2015 across all market sectors
  - The Technology Acceptance side of SAI is to reduce market barriers and promote market expansions of solar energy technologies through non-R&D activities

Source: Solar Energy Industries Association, Weekly Newsletter, May 19, 2006.

Tribes are eligible for incentives from a variety of sources. Tribes are also trying to leverage RECs.

Organization	Description	Examples
DOE Tribal Energy Program	• Provides financial and technical assistance to tribes for feasibility studies, and shares the cost of implementing sustainable renewable energy installations on tribal lands. • The financial assistance is done mainly through grants.	• In 2005, the DOE awarded grants between $100 - $250k • The Hualapai Tribe won a grant to establish a tribally operated utility-scale wind farm
USDA Renewable Energy Systems and Energy Efficiency Improvements Program	• This program currently funds grants and loan guarantees to agricultural producers and rural small business for assistance with purchasing renewable energy systems and making energy efficiency improvements.	• The Gila River Indian Community won a $500,000 grant to build a 500 kW PV power plant on tribal lands
National Rural Utilities Cooperative Finance Corporation	• Offers full-service financing, investment, and related services to its members, and offers a wide range of flexible, low-cost financing programs and interest rate options.	• Helped the Gila River Indian Community obtain a loan through the Clean Renewable Energy Bonds Program

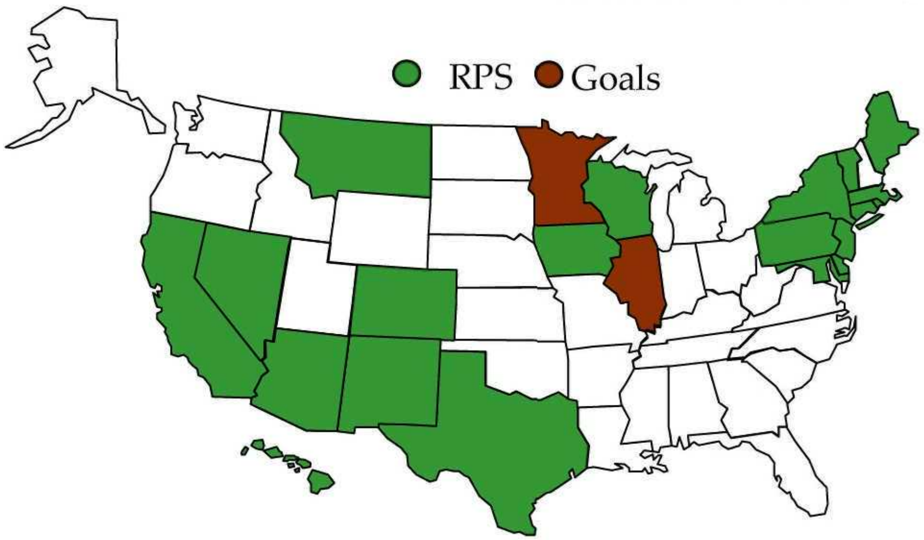
EPACT 2005 provides some additional incentives for tribes.

	Provisions Relevant to Indian Energy Under the Energy Policy Act of 2005
Title II: Renewable Energy	• Reauthorizes through 2023 the REPI (Renewable Energy Production Incentive) program, which provides renewable energy production incentive payments of 1.5 cents/kWh (adjusted for inflation and subject to appropriations) for solar, wind, geothermal, biomass and other renewable technologies • Adds Indian Tribal governments or "subdivisions thereof" to the list of qualified REPI participants • The use of biomass from Federal or Indian lands is encouraged by the creation of two grant programs to produce electric energy or heat from biomass and to improve biomass utilization technology
Title V: Indian Energy	• Provides grants, low-interest loans, loan guarantees and technical assistance, and streamlines the approval process for Tribal leases, agreements, and rights-of-way so that outside parties have more incentive to partner with Tribes in developing energy resources • Included in this title are provisions creating an Office of Indian Energy Policy and Programs within the Department of Energy to support the development of tribal energy resources • Makes Dine Power Authority, a Navajo Nation enterprise, eligible for funding under this title • Directs the Secretary of Housing and Urban Development to promote energy efficiency for Indian housing • Sections 2602 and 2603 instructs the Secretary of Interior to develop an Indian energy resource development program to provide grants and low-interest loans to tribes to develop and utilize their energy resources and to enhance the legal and administrative ability of tribes to manage their resources • Section 2602 creates a DOE loan guarantee program and directs the Energy Secretary to give priority to any project using new technology, such as coal gasification, carbon capture and sequestration or renewable energy-based electricity generation (no more than $2 billion at a time. • Section 2604 establishes a process by which an Indian tribe, upon demonstrating its technical and financial capacity and receiving approval of their Tribal Energy Resource Agreement, could negotiate and execute energy resource development leases, agreements and rights-of-way with third parties without first obtaining the approval of the Secretary of the Interior

Source: Red Mountain Energy Partners, May 2006 based on U.S. Senate Post Conference Bill Summary

PUC-IR-304
DOCKET NO. 2008-0273
ATTACHMENT 2
PAGE 45 OF 189

As of June 2006, 20 states plus DC had renewable portfolio standards (8 with solar or non-wind set asides).



	Target	Other
AZ[3]	1.1% by 2007 thru 2012	0.66% solar by 2007
CA	20% by 2017	
CO	10% by 2015	0.4% solar by 2015
CT	10% by 2010 (7% tier 1)	
DC	11% by 2022	0.386% solar by 2022
DE	10% by 2019	
HI	8% by 2005, 20% by 2020	
IA	105 MW (2% by 1999)	
IL[1]	8% by 2013	
MA	4% by 2009 (+1%/year after)	
MD	7.5% by 2019	
ME	10% additional by 2017. Starts in 2007 and increases 1%/year	Above the 30% for 2000. Includes some non-RE.
MN[2]	10% by 2015 (1% biomass)	
MT	15% by 2015	
NJ	6.5% by 2008 (4% tier 1), 20% by 2020	0.16% solar (95 MW) by 2008, 2% by 2020
NM	5% by 2006, 10% by 2011	
NV	20% by 2015	5% of RPS solar
NY	24% by 2013	0.154% customer-sited by 2013; includes 1% via green power
PA	18% by 2020 (8% is RE)	0.5% solar by 2020
RI	16% by 2019	
TX	5,880 MW by 2015	Includes 880MW pre-RPS & 500 MW non-wind
VT	New generation 2005-2012 RE	10% cap
WI	10% by 2015	

1. The Illinois RPS is a goal with a cumulative 2% cap on rate increases resulting from compliance with the goal
2. In Minnesota the RPS is mandatory for the largest utility, Xcel, however, for the rest of the utilities and service providers it is a "good faith effort". Under a separate agreement, and in addition to the RPS requirements, Xcel is required to build or contract for 125 MW of biomass electricity, and must build or contract for 1,125 MW of wind by 2010.
3. In 2/26/06 ACC approved revised RES of 15% by 2025 and 30% from DG by 2025. Final decision expected 7/31/06.

Source: Navigant Consulting, Inc. 2006, Database of State Incentives for Renewable Energy (DSIRE) and California Energy Commission.

RPS standards vary by the size of the requirement, the allowable resources, dates, use of technology tiers/multipliers and other factors.

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The AZ RES is under review by the Administrative Law Judge.

AZ Renewable Energy Standard (RES)

On Feb 27, 2006, the Arizona Corporation Commission gave preliminary approval of a revised Environmental Portfolio Standard (now a Renewable Energy Standard – RES), which is currently under review by the Administrative Law Judge who will prepare a recommended order for adoption by the Commission. Provisions include increasing the portfolio mix to 15% renewables by 2025 and an additional requirement that 30% of the renewables come from distributed generation resources. A final decision is expected by the end of 2006.

Under Arizona's RES, regulated utilities in the state are required to generate a certain percentage of their electricity with renewable energy according to the following schedule:
0.2% in 2001; 0.4% in 2002; 0.6% in 2003; 0.8% in 2004; 1.0% in 2005; 1.05% in 2006; 1.1% in 2007-2012
Eligible technologies include solar electric, solar water heating and solar air conditioning, landfill gas, wind and biomass. Solar electric power must make up 50% of total renewables required in 2001, increasing to 60% in 2004-2012. Arizona Public Service, a utility, has requested and received a rule waiver allowing it to meet a portion of its RES requirements using geothermal resources.

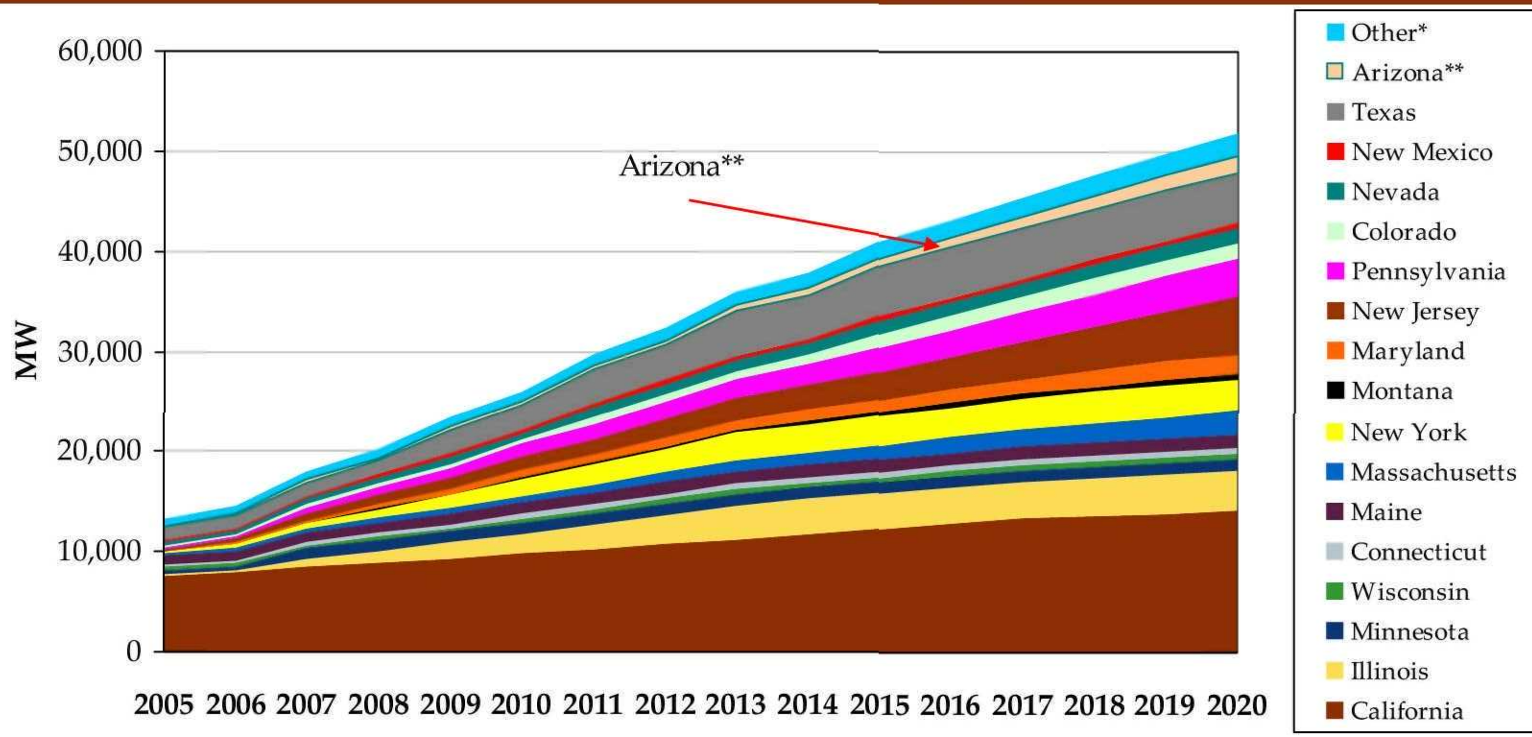
Funding for the RES comes from existing system benefits charges and a new surcharge to be collected by the state's regulated utilities. The existing surcharge is capped at $0.35 per month for residential customers, $13 per month for non-residential customers and $39 per month for customers with loads over 3 MW. At least $15 million-$20 million will be collected annually to support the RES.

Interestingly, the standard includes a caveat that if the cost of solar technologies does not decrease to a Commission-determined cost/benefit point by the end of 2004, the portfolio requirement will not continue to increase. On February 10, 2004, the ACC voted to allow the standard to continue increasing to 1.1% of electricity from renewables by 2007. Workshops will be held to determine whether the current surcharge on residential electric bills of up to $0.35 per month should be increased, and whether a requirement that 60% of the renewable energy come from solar resources should be modified or eliminated.

The RES requirement does not apply to Salt River Project, which is not regulated by the commission and has its own program to increase the use of renewable energy.

State RE standards are expected to support ~12,000 MW of existing capacity and result in ~52,000 MW of new capacity by 2020.

Estimated RPS Targets (MW)



Source: Navigant Consulting, Inc, February 2006.
- Other includes: Hawaii, Iowa, Rhode Island, Vermont, Delaware, and Washington D.C.
- ** The numbers for Arizona assume that the current resolution to raise the target to 15% passes

Note: Assumes maximum RPS target was achieved and held constant through 2020.

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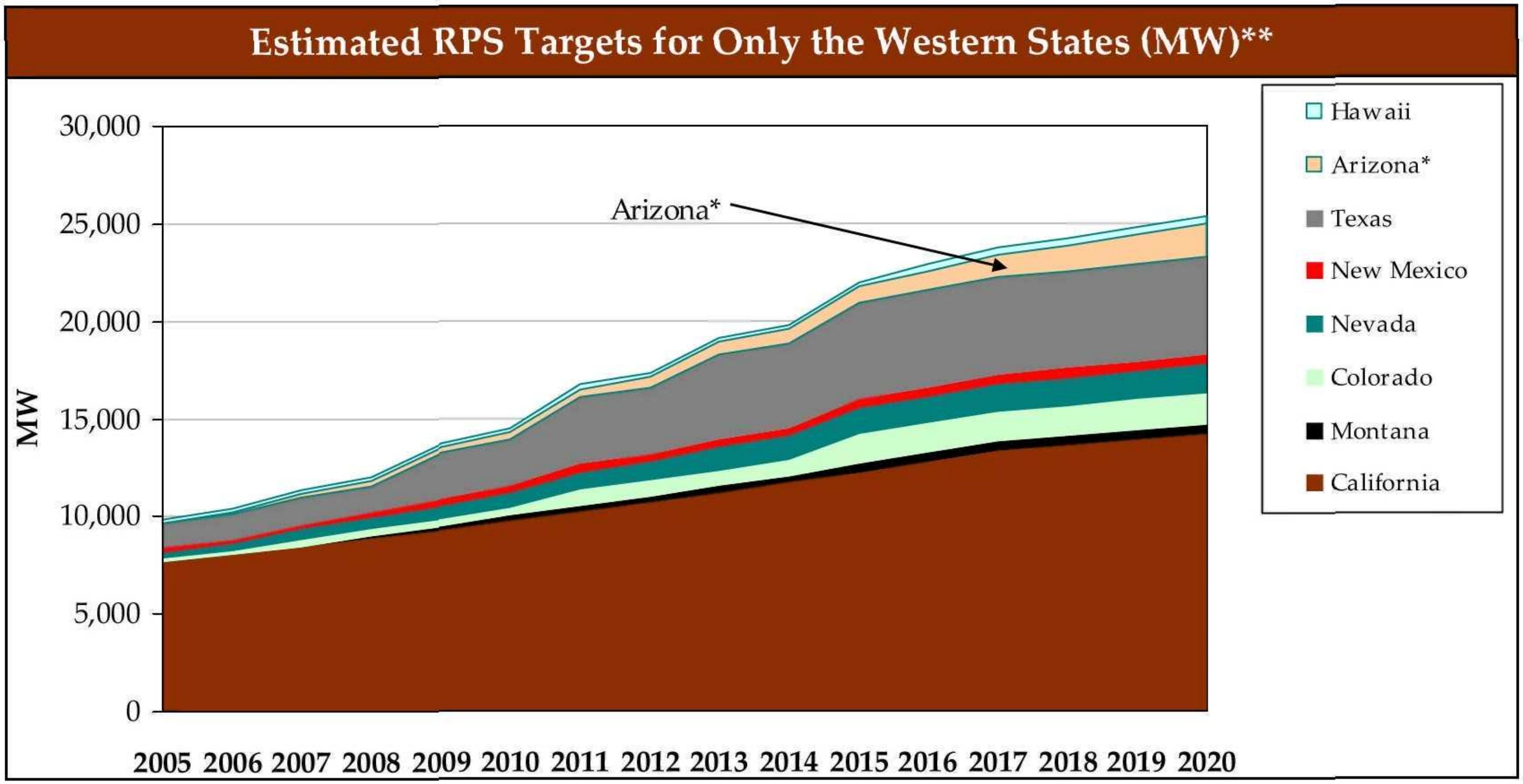
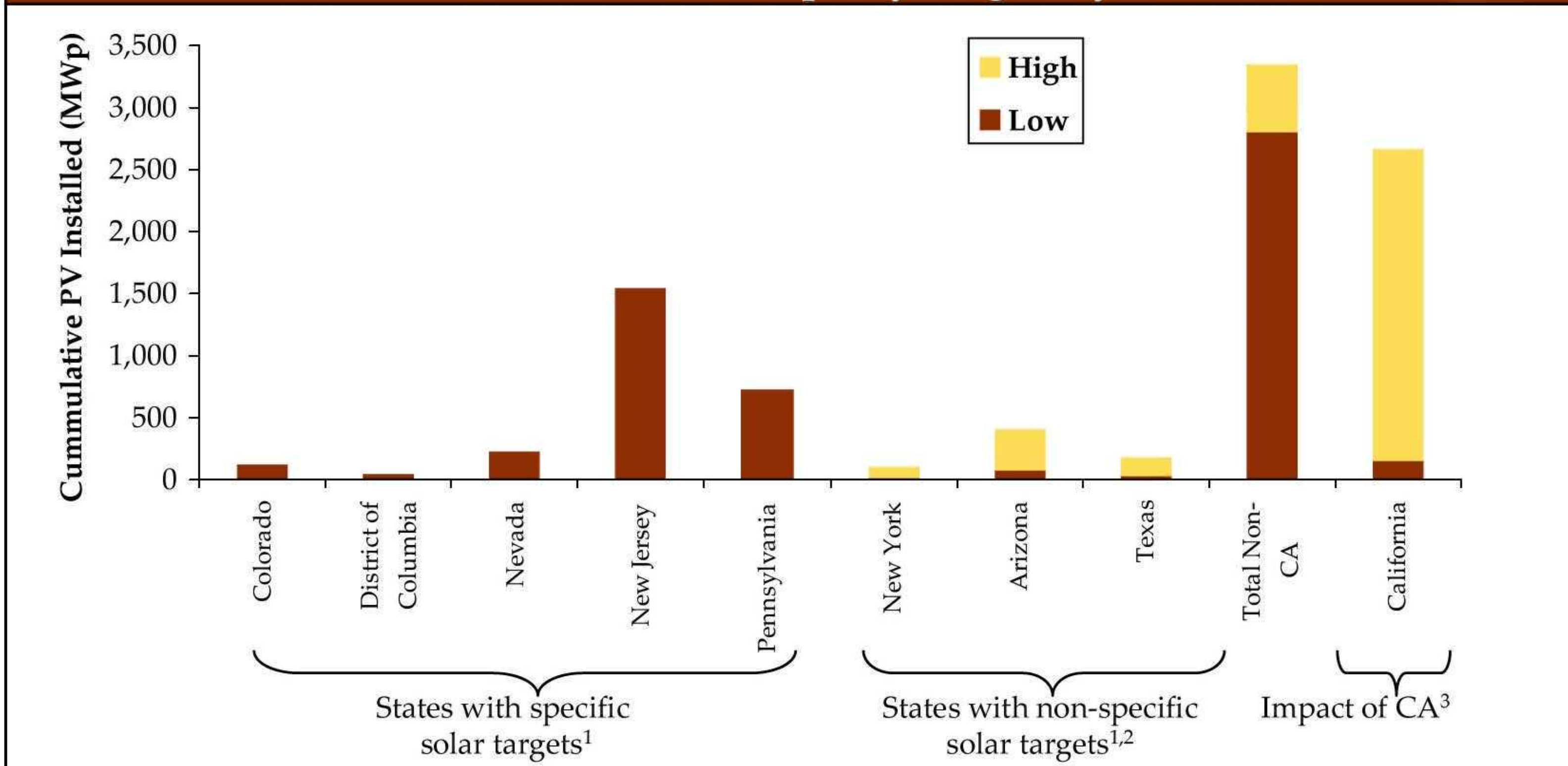
AZ will play some role in RPS growth in the western states.



Source: Navigant Consulting, Inc, May 2006.
*The numbers for Arizona assume that the current resolution to raise the target to 15% passes
**Assumes maximum RPS target was achieved and held constant through 2020.

The demand from RPS solar set asides could result in 3,000 to 3,500 MW of solar without CA, and up to 6,200 MW with CA by 2020.

Estimated Solar Set Aside Capacity Targets by 2020 (MW)



Source: Navigant Consulting Analysis, 2006

1. States have either specific solar targets as a % of generation or MW, or solar can be part of a non-wind set-aside or a DG set-aside. 2. Solar assumed to capture the following % of the state's RPS target: 0.2%-1.0% for NY, 1%-5% for TX, 3%-15% for AZ. For AZ, the 15% RPS target is assumed to have passed. 3.Lower bound for CA assumes installations stall at the 2005 installed capacity level. Upper bound assumes latest CA solar initiative is met.

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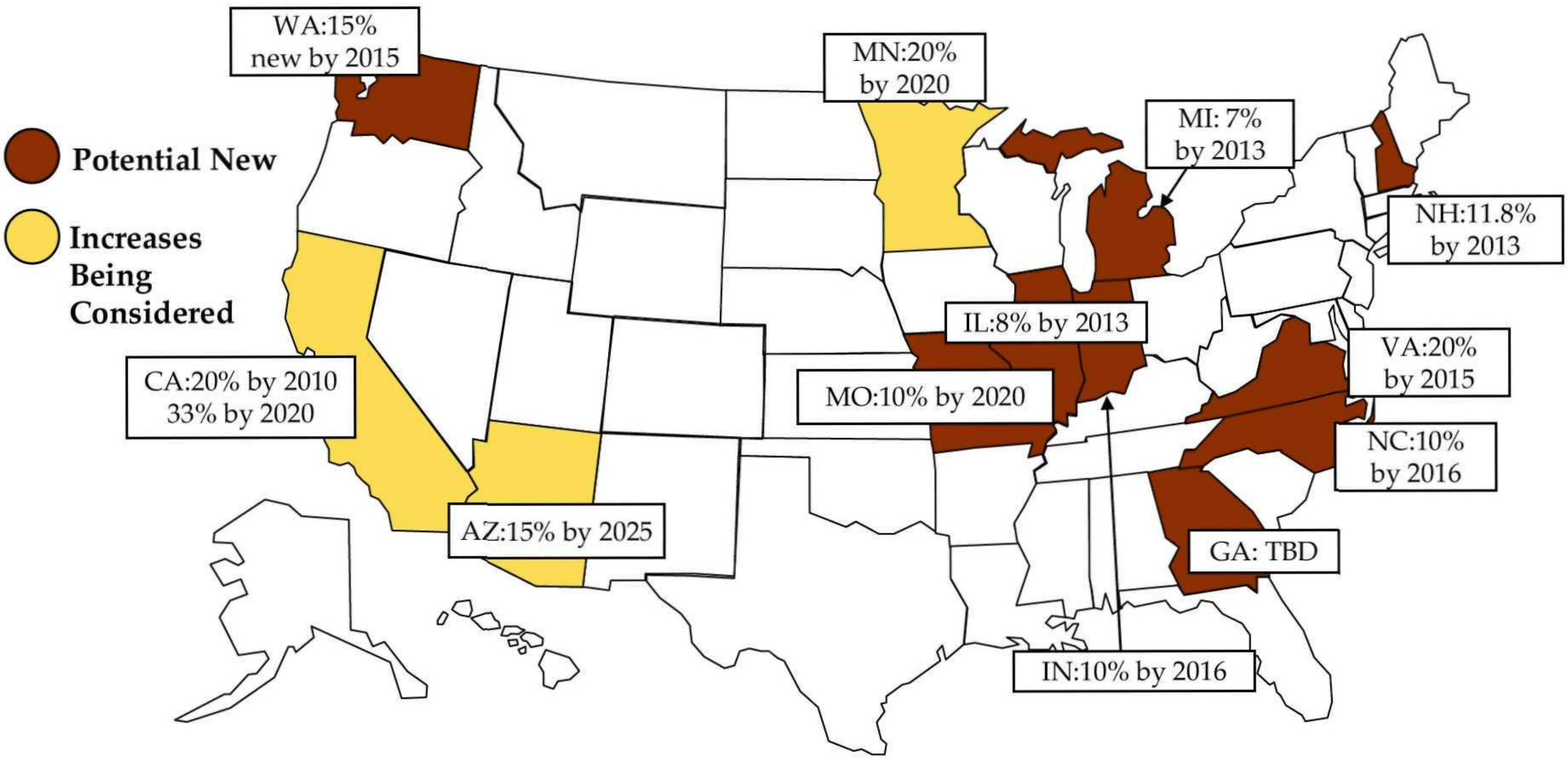
As of June 2006, nine states have RPS bills introduced and 3 are considering increasing RPS targets, including the AZ target.



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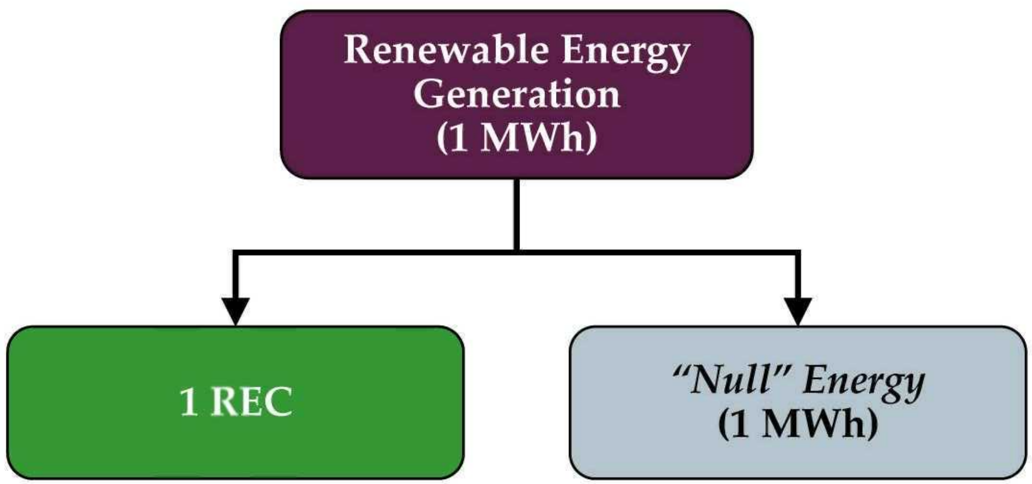
Renewable Energy Certificates (RECs) have emerged as a useful means for valuing the attributes of power sold to retail customers.



- Emission rate attributes
- Locational attributes
- Technology/fuel attributes
- Labor attributes
- Other

- Electrons without attributes (commodity electricity)

- RECs and the associated energy can be sold separately or together.
- A REC conveys the right to claim the attributes associated with electricity generated from a specific renewable facility.
- RECs are used to demonstrate compliance with RPS rules and also substantiate green power marketing claims. Certificates can also be used for labeling/ disclosure purposes.

Currently, the sale of RE attributes can add $10-50/MWh to project revenue (more for solar projects, less for "voluntary" RECs).

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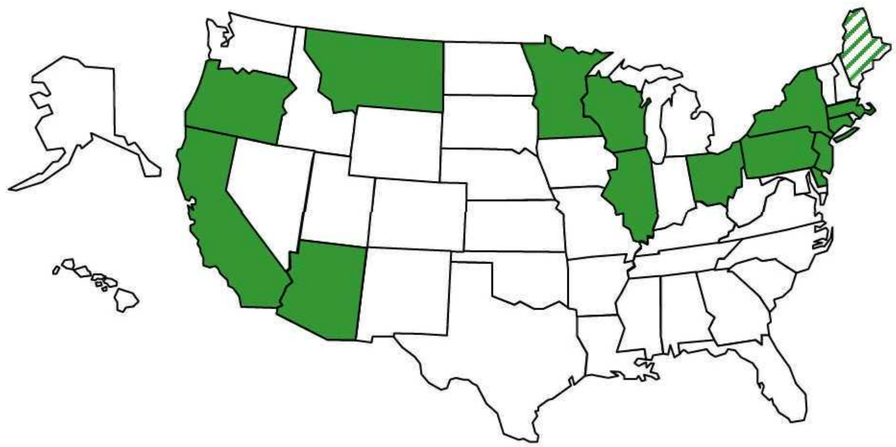
State renewable energy funds are expected to provide approximately $318 million in 2006.



Public Benefit Funds allocated to renewable energy funds

Voluntary Public Benefit Funds allocated to renewable energy

Annual Funding Available in 2006 ($ million)			
AZ	$13.5*	MT	$2
CA	$135	NJ	$68
CT	$20	NY	$13
DE	$1.5**	OH	$1.25
IL	$5	OR	$11
MA	$24	PA	$5.5
ME	voluntary	RI	$3.0
MN	$16	WI	$1.3

* In 2005 Arizona will generate an estimated $8.5m from PBFs and an additional $11-11.5m from a utility bill surcharge for renewable energy. Funds are given to utility to comply with Renewable Energy Standard (RES) through green power purchases, development of renewable generation assets and customer PV rebates. Arizona is currently modifying RES rules which could result in the elimination of PBFs for renewable energy, and instead create a utility bill surcharge to generate ~$50 million per year.

** Amount represents both renewable energy and energy efficiency programs.

Also, D.C. raised $9.5 million in 2005 using a PBF for renewable energy, energy efficiency and low-income programs.

Note: Values show are annual amounts for renewable energy only, and do not reflect total state system benefits charges.
Source: Navigant Consulting, Inc. estimates, January 2006.

Typical uses of funds include: rebates, grants, loans, feasibility studies, market support for RPS and green power, and education/outreach.

AZ incentives for solar are mostly provided by the utilities.

Key AZ Utility Solar Incentives

Utility Incentive	Incentive Amount	Comments
APS Solar Partners Incentive Program **(PV and SHW)**	• $3/W for residential and $2.50/W for commercial grid connected • $2/W for off-grid <5 kW • $.50/kWh for SHW	• Total cap per customer per year is $500,000 • $8.5 million total available for 2006
SRP EarthWise Solar Energy **(PV and SHW)**	• $3/W for residential and commercial PV up to 10 kW • As of July 5, 2006 the incentive level will be $2.50/W for PV systems >10 kW • $.50/kWh for SHW	• Maximum size for PV residential is 10 kW • Maximum amount of credit is $30,000 for residential and $500,000 for commercial
TEP SunShare PV BuyDown	• $2/Wpac Option 1 customer purchase • $2/Wpac Option 2 if purchased from TEP • $2.4/Wpdc Option 3 if customer purchased and operational within 180 days after receipt of agreement	
UES SunShare PV BuyDown	• $2.4/Wpdc for 1 – 5 kW if installed in 2006 for residential and commercial systems	• Incentives available for up to 50 kW of solar per year
Net Metering	• 10 kW for SRP • 10 kW for TEP (500 kW in aggregate)	

The regulated utilities are currently discussing a uniform credit purchase program for solar through the ACC.

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Some additional incentives are available at the state level.

Additional AZ State Level Solar Incentives and Other Related Programs		
Arizona Incentive	**Incentive Amount**	**Comments**
State Income Tax Credit	• 25% up to $1,000	• For residential only • Applies to all solar technologies (PV, SHW, and CSP)
Sales Tax Exemption	• Full sales tax exemption for solar energy systems	• Part of the recent HB2429 bill
Commercial Tax Credit	• 10% commercial tax credit capped at $25,000 per system and $50,000 per company annually	• Program capped at $1 million. Part of the recent HB2429 bill
AZ Enterprise Zone	• $3,000 for each net-new qualified employee over a 3-year period for a maximum of 200 employees in any given tax year. • A reduction of assessment ratio from 25% to 5% of all personal and real property for primary tax purposes for 5 years	• An effort to improve economies of designated areas in AZ by enhancing opportunities for private investment.
Property Tax Exemption	• Full property tax exemption for property owners installing solar energy systems	• Part of the recent HB2429 bill
Interconnection	• ACC is developing a statewide interconnection standard, but this is still in progress	
Job Training Program	• Provides grant money to companies creating full time permanent new jobs or training for existing worker within AZ	
AZ Workforce Connection	• Provides free services to employers who seek access to skilled new hires or existing worker training resources	

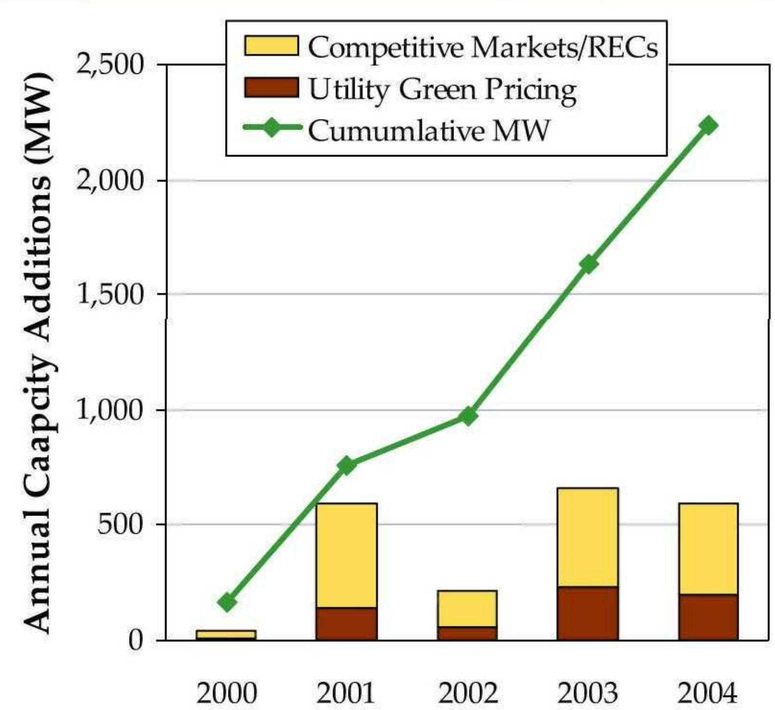
There has been a tenfold increase in capacity supplying green pricing programs since 1999, but wind represents about 80% of the capacity.

- Currently about 600 utilities, including investor-owned, municipal utilities, and cooperatives, have either implemented or announced plans to offer a green pricing option[1]
- Competitive green power products are available in 10 states and in DC, from more than 30 suppliers
- A growing number of REC-based products are also available
- Average premium is 2.45 cents/kWh
- Some of the most successful green pricing programs have experienced 3 – 5% market penetration

1. Because a number of small municipal or cooperative utilities offer programs developed by their power suppliers, the number of distinct green pricing programs is just more than 100.

Source: DOE - EERE Green Power Network; *Green Power Marketing in the United States: A Status Report,* Eight Edition Lori Bird and Blair Swezey, NREL, October 2005.

New Renewable Energy Capacity Serving Green Pricing Programs



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Many policy options encourage widespread adoption of solar.

Objectives	Strategies	Tactics	Policy & Program Options
Provide financial incentives to stimulate market	Provide tax incentives	Federal incentives	• Extend 30% ITC (including IOUs) for 10 years • Continued support for accelerated treatment of depreciation
		State incentives	• Sales and property tax exemption • Tax credit for distributed generation investments • Manufacturing tax credits
	Provide direct incentives	Capital cost subsidies	• Up-front, declining buy-downs for PV and thermal that attain targeted payback periods for system owners
		Production-based subsidies	• Performance-based incentives such as per-kWh payments over guaranteed period of time
***Facilitate easy* access to solar**	*Maximize availability* of solar resource	*Solar access*	• *Solar enterprise zones* • Statewide solar access rules/solar "rights" policies
	Expedite development	Permits & approvals	• Streamline siting, permitting, zoning
		Common interconnection standards	• Allow for the connection of pre-certified systems • Establish reasonable timelines for utility responses to applications • Eliminate undue fees and insurance requirements • Establish dispute-resolution process • Transparency and consistency among utilities and states

Source: WGA Solar Task Force Report, Clean & Diversified Energy Initiative,. Appendix II-3, January 2006.

NAVIGANT CONSULTING

Many policy options encourage widespread adoption of solar.

Objectives	Strategies	Tactics	Policy & Program Options
Provide ongoing support	Demonstrate leadership	Advocacy	• Encourage "Zero Energy Buildings" • Public education programs to promote efficiency, alt. energy
		Public purchasing	• Purchase distributed solar for public buildings • Purchase solar under long-term power purchase agreements
		Regulatory & market stability	• Establish stable, long-term programs (minimum 10 years) • Structure incentive programs to attract investment (e.g., 10-year payback for residential, 5 years for businesses) • Design programs to support self-sustaining markets • Encourage participation by publicly-owned utilities
		Low-cost capital	• Tax-free solar bonds for public projects • Long-term debt financing • Government guarantees (loan or performance) • Public-private partnerships
	Encourage optimized production	Net metering	• Credit customer for excess energy generated and supplied to the grid
		Alternative rates	• Encourage optional rate structures that incentivize PV, including time-of-use tariffs
		Create revenue stream	• REC trading and ownership

Source: WGA Solar Task Force Report, Clean & Diversified Energy Initiative,. Appendix II-3, January 2006.

Several states have incentives specifically to lure solar and other renewable energy manufacturers.

State	Program	Description
WA	Tax Abatement for Solar Manufacturers	• 40% reduction of the Washington state Business and Occupation tax of 0.484% • This applies to manufacturers and wholesale marketers of PV modules or silicon components of those systems
TX	Solar Energy Business Franchise Tax Exemption	• Exemption from the Texas state franchise tax for corporations • This applies to solar electric and solar thermal manufacturers
NY	Renewable Energy Technology Options Program	• Up to $540,000 in funding awards • Specifically for individuals or corporations to develop, demonstrate, commercialize, market or improve manufacturing methods from solar electric, wind, biomass, and hydro technologies
NY	Renewable Energy Technology Manufacturing Incentive Program	• $1 million award per project • For renewable energy technology manufacturers to develop or expand facilities for production of systems and components related to solar electric, wind, biomass, and hydro technologies
VA	Solar Manufacturing Incentive Grant Program	• Between $.25 and $.75/W for PV panels sold in a calendar year for panels manufactured in VA • Program expires at the end of 2007
MI	Refundable Payroll Credit	• Business located in the NextEnergy zone may claim a tax deduction for their pay roll amount • Applies to most renewable and clean energy technologies
MI	Nonrefundable Business Activity Credit	• Partial state tax credit for manufacturers that locate to the NextEnergy zone in MI • Applies to most renewable and clean energy technologies

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There are also several states that foster R&D in renewable energy.

Examples of State Renewable Energy R&D Activities

State	Organization	Purpose
NY	New York State Energy Research and Development Authority (NYSERDA)	• NYSERDA is funded by a charge on the electricity transmitted and distributed by the state's investor owned utilities • Focuses on fostering R&D in energy that benefits NY citizens and economy
NC	North Carolina Solar Center	• State funded research institute for renewable energy research and development
MA	Massachusetts Technology Collaborative (MTC)	• MTC focuses on innovation to drive the renewable energy industry in Massachusetts • Provides funding for innovation
FL	Florida Solar Energy Center	• State funded research institute for renewable energy R&D
CA	California Energy Commission's Public Interest Energy Research (PIER) and Energy Innovations Small Grant (EISG) programs	• PIER provides funding to organizations involved in R&D that will improve the quality of life in CA • EISG provides funding of $50k to $95k to small businesses, individuals, and academic institutions for hardware and modeling projects to establish feasibility of new energy concepts
AZ	Solar Test and Research Center (STAR) and ASU	• STAR: Solar research for APS, solar equipment manufacturers, scientists, engineers, and students from around the world. STAR is the largest facility of its kind in the world. ASU also has significant resources for solar R&D and education

Note: Ohio is also currently seeking proposal for a solar center

In January 2006, CA passed a landmark resolution to foster the growth of the solar industry.

- The Commercial and Existing Residential Buildings (CERB) incentive for PV will initially be $2.50/W and will decrease approximately 10% per year until 2016.
- Incentives for solar thermal electric, solar heating, and solar cooling are included.
- 10% of the funds are tagged for low income and affordable housing.
- Incentives for the Residential New Construction Component (RNCC) portion are still in discussion, but they will focus on creating a market with builders and developers of new housing.

$2.9 Billion (2007 – 2016)

$2.5 Billion to CERB Program	$350 Million to the RNCC
Funded through surcharge on customer bills for CA's 4 investor owned utilities	Funded through a Public Goods Charge that will be collected from 2007 to 2011
Program administered by the CPUC	Program administered by the CEC

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NYSERDA has focused on training/certification to build a credible installation and distributor network to support a sustainable market.

New York State Energy Research and Development Authority (NYSERDA) Business Development Activities for a Sustainable Renewable Energy Market

Qualified Installers and Market Tested Products/Systems → **Multiple Distribution Pathways** → **Informed Customers** → **"Reachable" Cost** → **Sustainable Market**

Accredited Training , Installer Certification
[Institute for Sustainable Power & North American Board of Certified Energy Practioners]

NYSERDA

Photovoltaic Incentive Program
Small Wind Incentive Program

[RPS Customer-Sited Tier]

Innovative Business Development (stressing infrastructure development)
[PON 949 $2 million]

Targeted Outreach and Analytical Tools
Brochures, Clean Power Estimator, powernaturally.org

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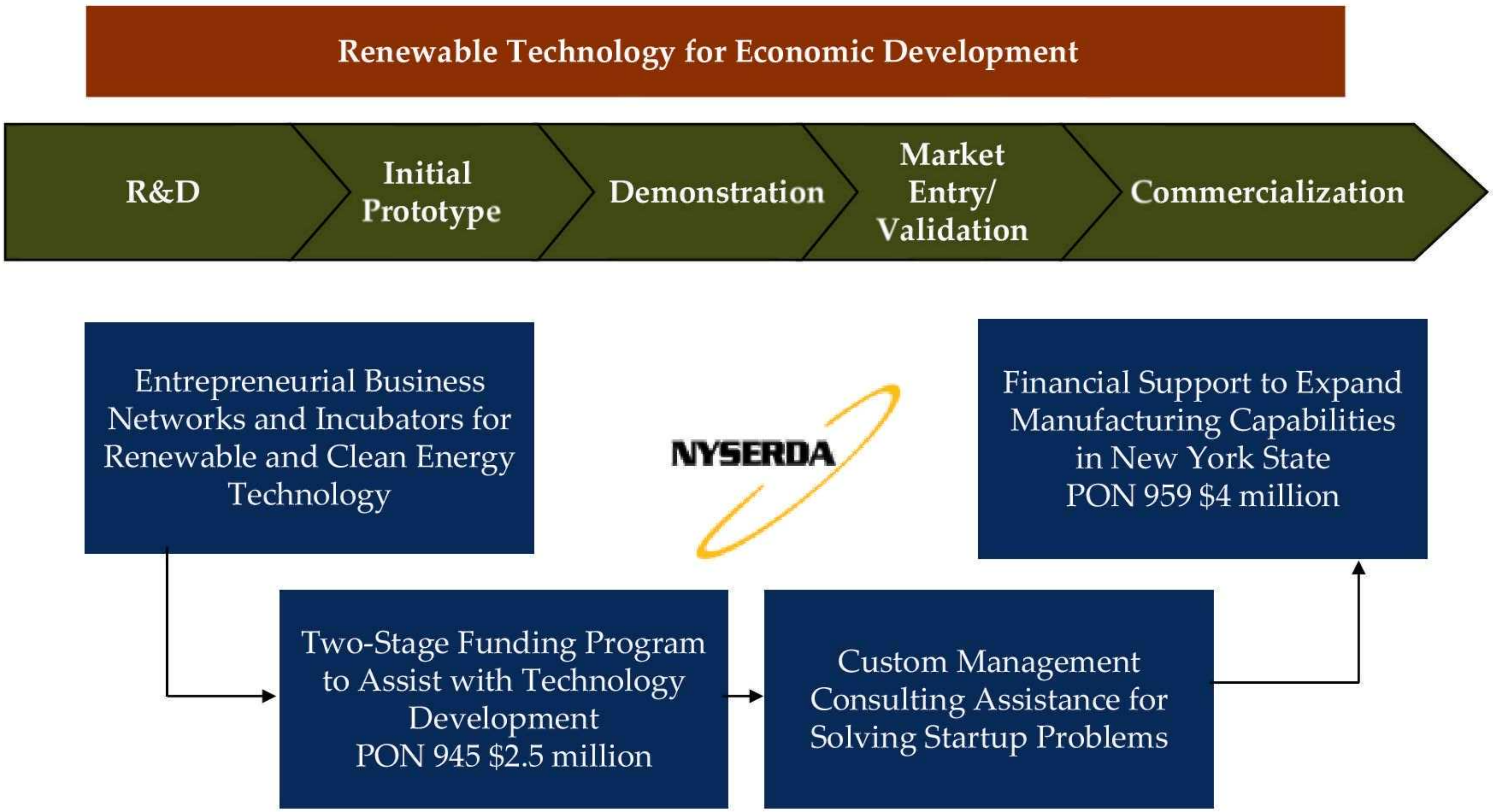
NYSERDA has also worked to support development of renewable energy technology and manufacturing companies that will add jobs.



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NY is one of several states that have added incentives to specifically lure solar and other renewable energy manufacturers.

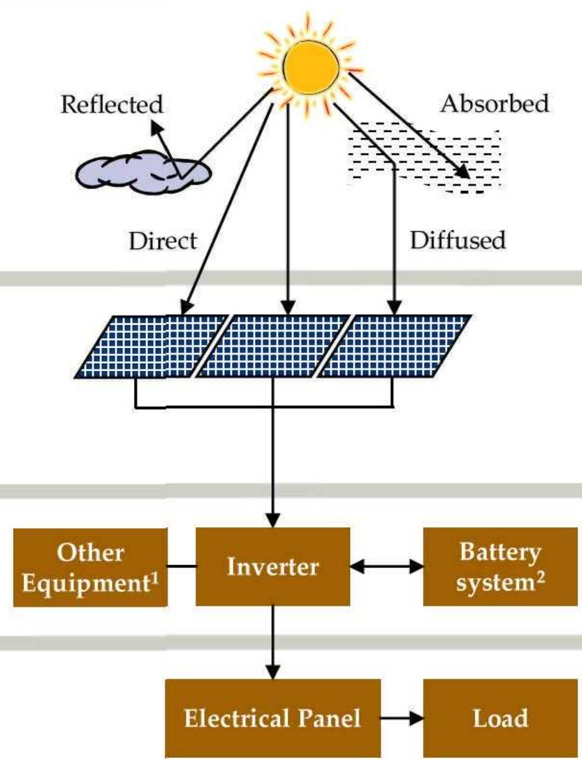
Program	Comments
Innovative Business Development	• $2 million solicitation (initial funding) issued for the first time this year. Proposals due May 3, 2006 from companies located in or wishing to locate in NY that will result in NY business to assemble, install, distribute, sell and/or service electric renewable energy. Focus on infrastructure development Greater impact on reducing PV costs and increasing manufacturing than mnf incentives. Cannot be used for manufacturing and development of products
Training/ Certification	• Goal is to expand qualified installer base which NYSERDA believes is key to any successful PV program
Technology Development	• $2.5 million initial funding, proposal rounds every 6 months. Proposals due May 30, 2006. This program is designed to share the risk of early stage technology and product development, e.g. technology development, prototype construction, demonstration and manufacturing improvements • Two stage program. Stage 1 is smaller award for things such as feasibility studies ($40 – 50k). Stage 2 helps commercialize the product or provides money for beta tests (~$250k). Idea is to have companies move from Stage 1 to 2 over the course of time.
Financial Support for Manufacturing	• $4 million initial funding, next round of proposals due June 1, 2006. Provides performance-based financial support to companies that want to expand the manufacturing of renewable energy technologies in NY. Funding to assist in expanding manufacturing capacity or for moving technology developed in above programs into manufacturing. • 2 years ago DayStar came in to NY with a $1 million award. 25% was used for capital purchases. The rest of the dollars were for sales or performance payments. – Also agreed to locate in STEP (Saratoga Technology Energy Park), a NYSERDA funded industrial park for alternative energy companies. – If they do not deliver, they do not get the money and they negotiate with NYSERDA regarding the time they can achieve the milestone (typically up to 5 years)
Business Support	• Contractors selected to help in oversight/evaluation of contracts. Provide business support to NY companies

Source: Interview with NYSERDA, May 2006.

Table of Contents

Photovoltaic technology converts solar energy into usable electrical energy.

From Sun to Power Outlet



Solar Resource	**Solar energy falling on a PV module can be either direct or diffused.**
PV Panel	**DC electrical energy output from PV modules is a function of module operating characteristics and external conditions.**
Balance of System (BOS)	**AC electrical energy from PV system is a function of system efficiency. An inverter is required to convert DC power to AC**
Load	**AC electrical energy consumption by load**

[1] Other equipment includes mounting structure, switches & fuses, meters, wires & conduits, isolation transformers/ automatic lock-out switches, etc.

[2] Battery system is optional and include batteries, charge controller and battery enclosure

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Flat plate PV were evaluated for three primary applications.

Residential

Central (single-axis tracking)

Commercial

Flat plate PV technology is well proven, but system economics require incentives to be competitive with retail rates.

Flat Plate PV Technology	• Crystalline silicon technologies have module efficiencies of around 14.5% and system efficiencies of 12.3%. • The technology has over 25 years of proven and reliable performance in the field. • Inverters, which used to be the main problem area for PV systems, have improved in performance and reliability over the past several years. Inverter efficiency is now about 95%. • The PV industry is active in terms of R&D: several companies are developing next generation PV technologies such as thin films (CdTe, CIS, Spheral Solar) and there continues to be innovation with proven, crystalline silicon. – Sanyo has developed a very high efficiency solar cell (HIT) that results in about 35% increase in an annual output over existing crystalline silicon modules.
Economics	• A recent surge in demand and a shortage of silicon prices has caused the cost of installed systems to spike 5% to 20%, depending on the geographic market. Over the long-term, prices are expected to decline approximately 4 - 5% per year. • Solar resources in AZ are very good and provide an effective capacity factor of between 18% to 25% depending on the angle and amount of tracking.

1. kWpac = kW peak, alternating current.

PV can be sited at customer premises to compete with retail power, but high first cost is still a major barrier to broader market penetration.

Advantages

- Modular
- Well suited to customer-sited applications, and can defer some T&D losses and upgrades
- No land costs (if building mounted)
- Proven reliability
- PV output is a good match with peak demand, thus offsetting the most expensive power.
- Minimal O&M costs (no moving parts), plus inverter replacement typical in year 10.
- Cost-effective today in many off-grid markets such as telecommunications, water pumping, rural electrification.

Challenges

- Polysilicon shortages, the raw material used to make 93% of 2005 PV modules, has resulted in a temporary module shortage
- Very high capital costs relative to conventional power options
- Intermittent resource
  - Need energy storage to be able to operate completely independent of the grid
- Lack of infrastructure for sales/service (generally)
- Poor consumer knowledge about the reliability of systems
- Lack of simple interconnection standards (this is not a disadvantage of PV itself, but rather a barrier to more widespread adoption)

Installed residential prices in 2006 were high due to the module shortage, but are expected to drop again starting in 2008.

	Residential PV Economic Assumptions for Given Year of Installation (2006$)			
	2006	**2010**	**2020**	**2025**
System Capacity (kW)	2.5 - 3	2.5 - 3	2.5 - 3	2.5 - 3
Total Installed Cost ($/kWac)[1]	$9,000	$7,900	$3,800	$2,650
Non-Fuel Fixed O&M ($/kW-yr)[2]	$15	$13	$11	$11
Capacity Factor (%) – Phoenix	18.3%	18.3%	18.3%	18.3%
Project Life (yrs)	25	25	30	30
CO2 (lb/kWh)	No air emissions			
NOx (lb/kWh)				
SOx (lb/kWh)				

1. kW peak alternating current. An 82% DC to AC rating factor is assumed that takes into account system losses (dust, wiring, module mismatch), system equipment efficiencies (inverter) and impact of temperature on PV system output.
2. Excludes inverter replacement, which is assumed to occur every 10 years.

Source: NCI estimates based on industry interviews, 2006. Capacity factor estimates based on discussions with Herb Hayden at APS and analysis using PV WATTS, May 2006. 2006 installed costs from AZ Department of Commerce, Installed Cost Survey for May 2006. 2006 install costs based on interview with Kyocera Solar, June 2006.

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Commercial systems are cheaper than residential as they are typically installed on large roofs and benefit from the economies of scale.

	Commercial PV (flat roof) Economic Assumptions for Given Year of Installation (2006$)			
	2006	**2010**	**2020**	**2025**
System Capacity (kW)	50 - 300	50 - 300	50 - 300	50 - 300
Total Installed Cost ($/kWac)[1]	$7,500	$6,200	$3,300	$2,500
Non-Fuel Fixed O&M ($/kW-yr)[2]	$30	$26	$22	$22
Capacity Factor (%) – Phoenix	16%	16%	16%	16%
Project Life (yrs)	25	25	30	30
CO2 (lb/kWh)	No air emissions			
NOx (lb/kWh)				
SOx (lb/kWh)				

1. kW peak alternating current. An 82% DC to AC rating factor is assumed that takes into account system losses (dust, wiring, module mismatch), system equipment efficiencies (inverter) and impact of temperature on PV system output.
2. Excludes inverter replacement, which is assumed to occur every 10 years.

Source: NCI estimates based on industry interviews, January 2006. Capacity factor estimates based on discussions with Herb Hayden at APS and analysis using PV WATTS, May 2006. 2006 installed costs based on data from AZ Department of Commerce, Installed Cost Survey for May 2006 and NCI analysis.

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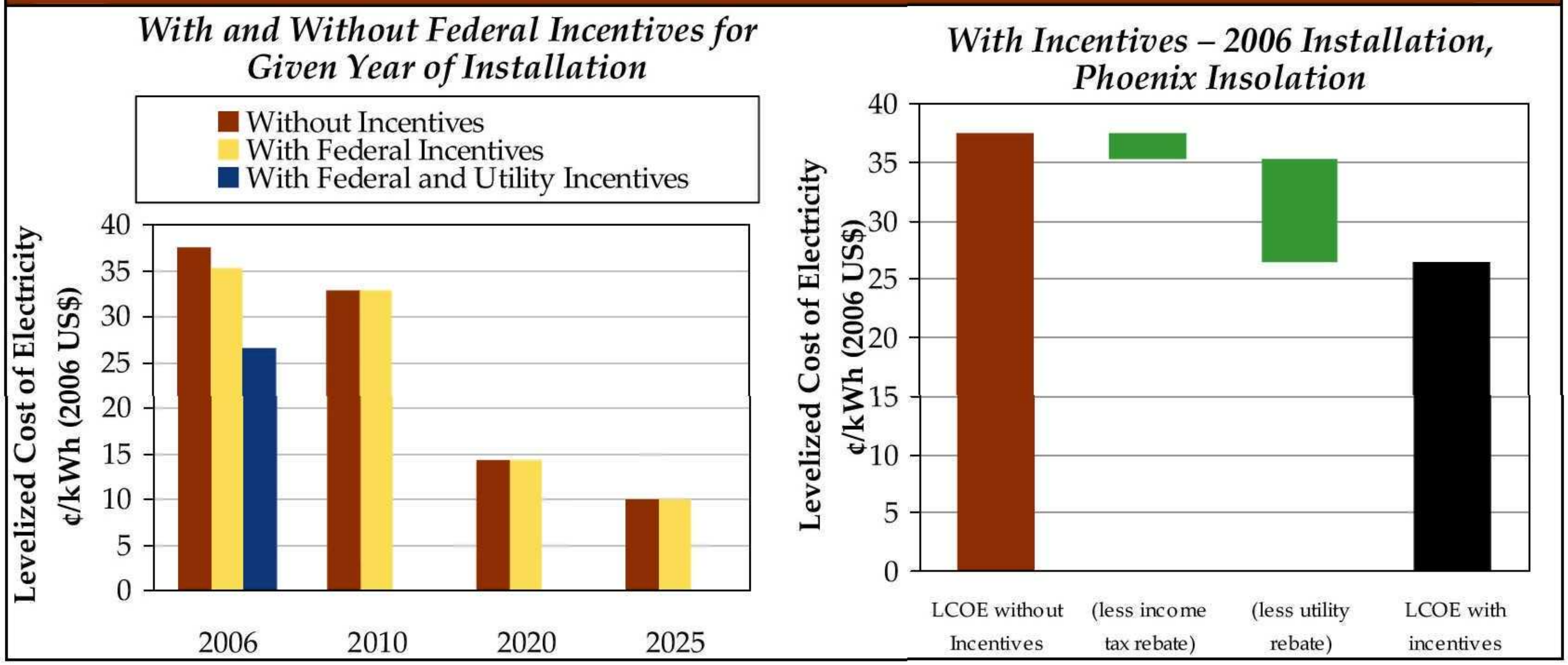
If PV prices continue to fall, residential PV will be affordable in the future.

AZ Levelized Cost of Electricity for Residential PV (2.5 – 3 kW in Size)

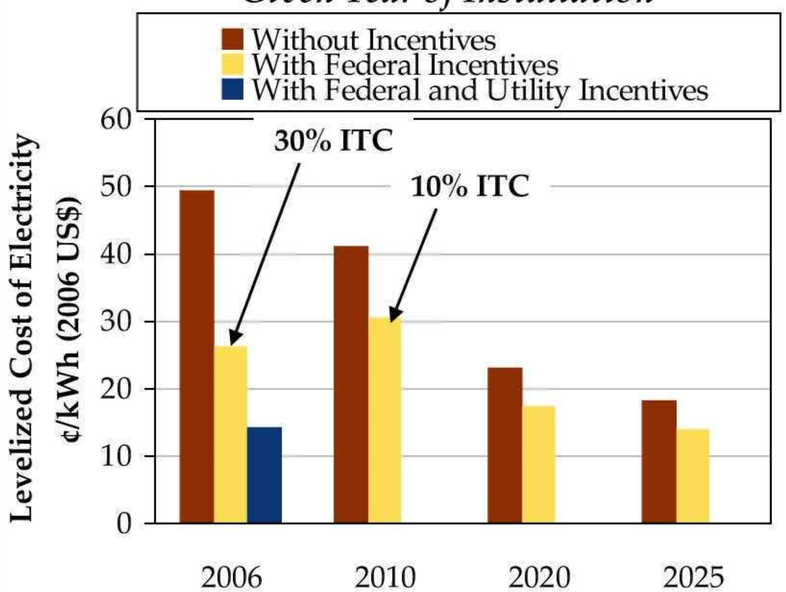


Key assumptions without incentives: Debt equity ratio: 100% debt, cost of debt = 6.25%, Insurance = 0.5%, Loan period = 10 years. Project economic life (for property tax calculations) = 25 years. Property tax rate of $11.70/$100 of assessed value. Electricity cost of .095$/kWh growing at 1%/yr. Key assumptions with incentives: Federal Tax Credit of 30% for 2006, capped at $2000. Assume that the Federal Tax Credit ends at the end of 2007. For the 2006 local incentive, assumed rebate of $3/Wdc, capped at 50% of the system cost This is the current APS incentive.

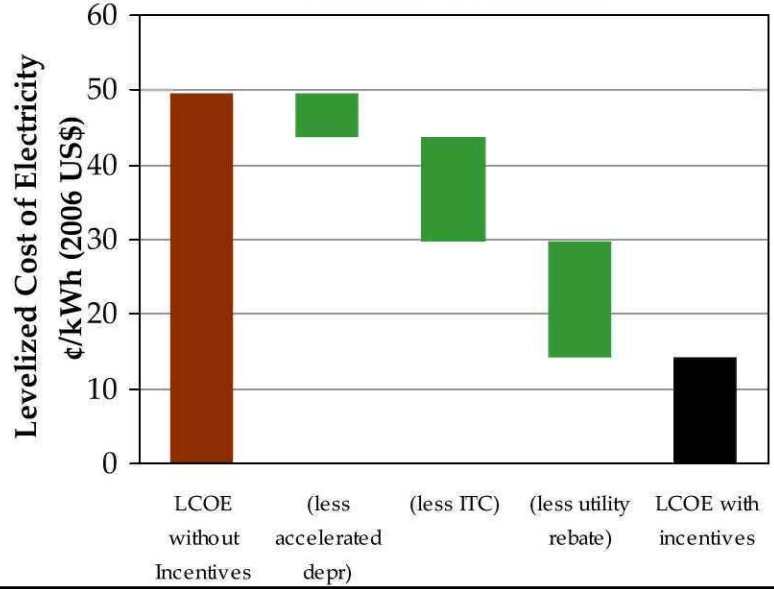
The 30% Investment Tax Credit (ITC) has a significant impact on project economics.

AZ Levelized Cost of Electricity for Commercial PV (50 – 300 kW in Size)

With and Without Federal Incentives for Given Year of Installation



With Incentives – 2006 Installation, Phoenix Insolation



Key assumptions (without incentives): Debt equity ratio: 55%:45%, cost of equity = 15%, cost of debt = 8%, Marginal federal + state income tax = 41%. Insurance = 0.5%, Depreciation under Modified Accelerated Cost Recovery System (MACRS): Depreciation period considered is 15 years. Loan period = 10 years. Project economic life (for property tax calculations) = 25 years. Property tax rate of $11.70/$100 of assessed value. Electricity cost of $.07kWh growing at 1%/yr. Key assumptions (with incentives): Accelerated depreciation under MACRS 5 year schedule. Federal investment tax credit = 10% of **total installed** cost in year 1 after 2007. Currently the incentive level is 30%, but this is due to expire in 2007. Local incentives of $2.5/Wdc, capped at $500,000. This is the current APS incentive.

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Central Station PV are expected to have similar cost structures to commercial systems.

	Central Station PV – Single-Axis Tracker Economic Assumptions for Given Year of Installation (2006$)			
	2006	**2010**	**2020**	**2025**
Plant Capacity (MW)	5	5	8	8
Total Installed Cost ($/kWac)[1]	$8,000	$6,600	$3,600	$2,600
Non-Fuel Fixed O&M ($/kW-yr)[2]	$30	$26	$22	$22
Capacity Factor (%) – Phoenix	25%	25%	25%	25%
Project Life (yrs)	25	25	30	30
CO2 (lb/kWh)	No air emissions			
NOx (lb/kWh)				
SOx (lb/kWh)				

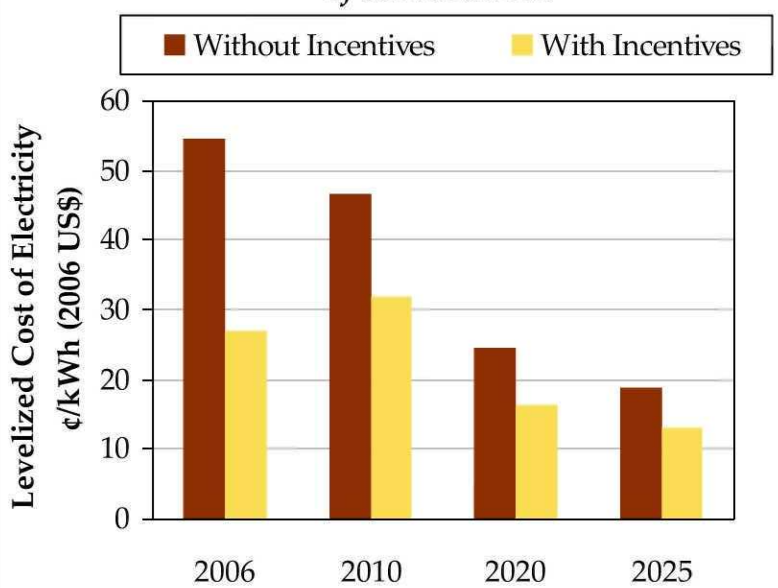
1. kW peak alternating current. An 82% DC to AC rating factor is assumed that takes into account system losses (dust, wiring, module mismatch), system equipment efficiencies (inverter) and impact of temperature on PV system output. Excludes land costs. Land required is approximately 5 acres per MWac (Land source: STAR Facility, Interview with Herb Hayden, 5/2006.
2. Excludes inverter replacement, which is assumed to occur every 10 years.

Source: NCI estimates based on industry interviews, January 2006. Capacity factor estimates based on discussions with Herb Hayden at APS and analysis using PV WATTS, May 2006.

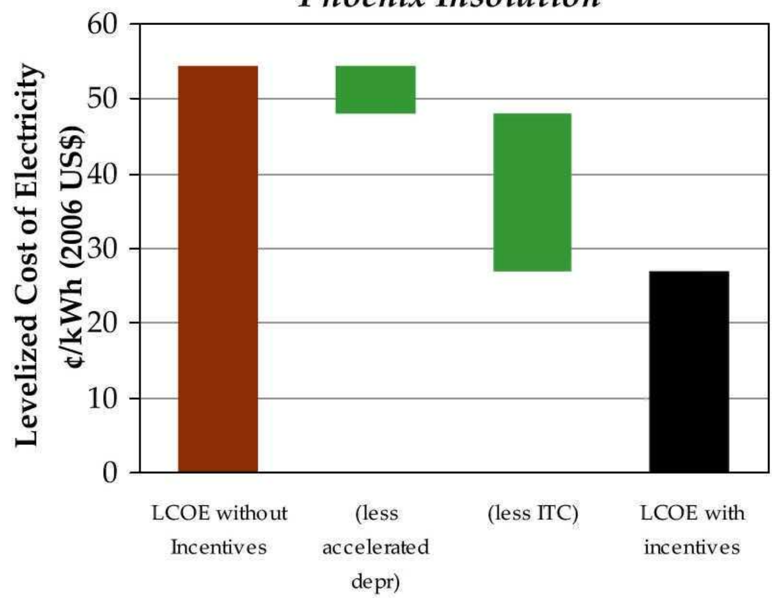
Flat plate PV with tracking costs may be competitive after 2010 as well.

AZ Levelized Cost of Electricity for Flat Plate PV, Single Axis Tracking, Developer Financed

Without Federal Incentives for Given Year of Installation



With Incentives – 2006 Installation, Phoenix Insolation



Key assumptions (without incentives): Debt equity ratio: 55%:45%, cost of equity = 15%, cost of debt = 8%, Marginal federal + state income tax = 41%. Insurance = 0.5%. Loan period = 10 years. Project economic life = 25 years. Property tax rate of $11.70/$100 of assessed value. Depreciation under Modified Accelerated Cost Recovery System (MACRS): Depreciation period considered is 15 years. Key assumptions (with incentives): Accelerated depreciation under Modified Accelerated Cost Recovery System (MACRS) 5 year schedule. Federal investment tax credit = 10% of **total installed** cost in year 1 after 2007. Note currently the incentive level is 30%, but this is due to expire in 2007.

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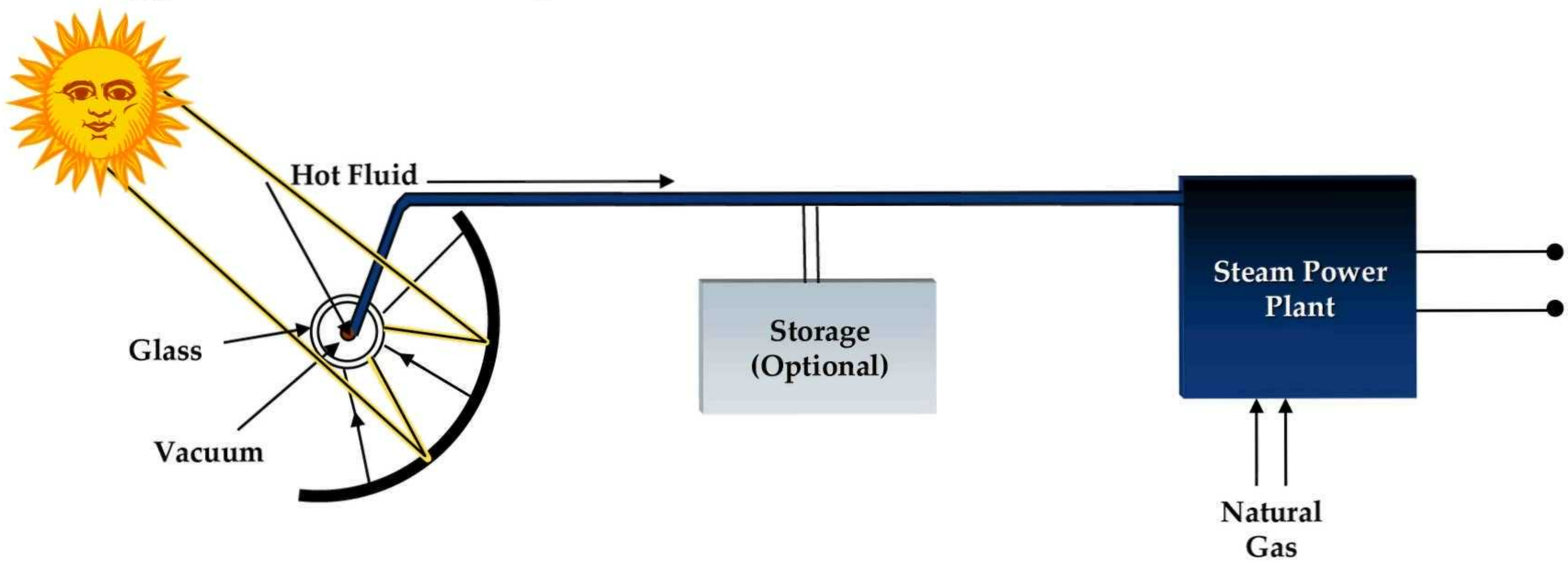
All solar thermal electric (STE) processes use concentrated solar energy to raise the temperature of a heat transfer fluid.



"Co-firing" with natural gas is commonly considered in order to stabilize operation and ensure a dispatch capability.

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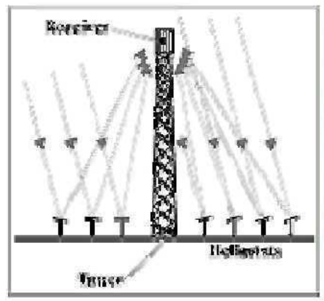
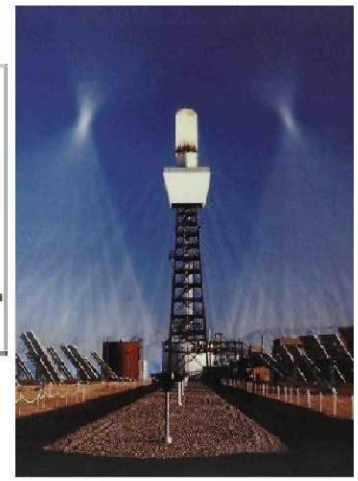
Solar thermal electric technologies convert solar energy into heat for use by a turbine generator or heat engine.

Three Basic Solar Thermal Electric Technologies

Parabolic Trough





Power Tower

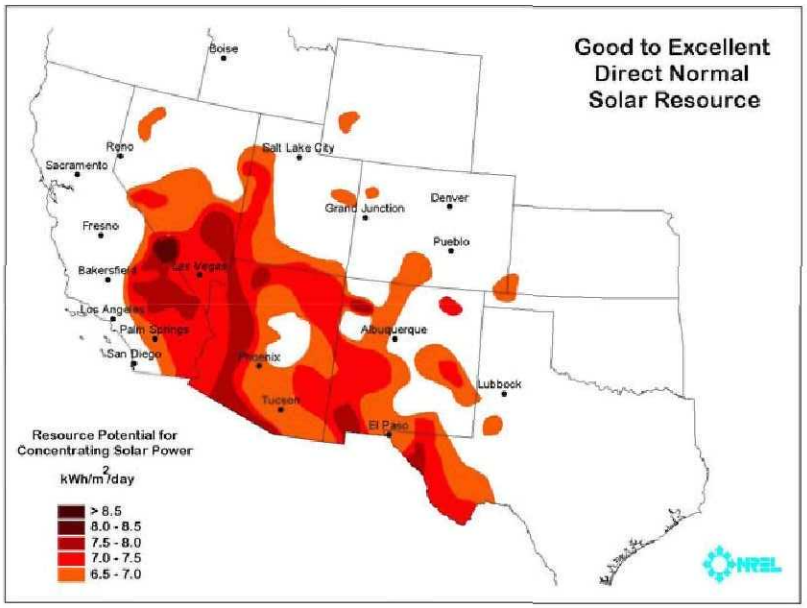
Solar Dish

Each technology employs some type of concentrator to focus energy on a receiver that contains an oil or another fluid that is heated.

NAVIGANT CONSULTING

AZ has excellent solar resources to both flat plate and concentrating solar power technologies.

Resource Potential for Concentrating Solar Power (kWh/m2/day)



Source: National Renewable Energy Laboratory.

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The National Renewable Energy Laboratory estimates the technical potential for concentrating solar power at ~2.5 GW in Arizona.

State	Land Area (mi^2)	CSP Capacity[1] (MW)	CSP Generation Capacity (GWh)
AZ	19,300	2,467,700	5,836,500
CA	6,900	877,200	2,074,800
CO	2,100	271,900	643,100
NV	5,600	715,400	1,692,200
NM	15,200	1,940,000	4,588,400
TX	1,200	148,700	351,800
UT	3,600	456,100	1,078,900
Total	**178,400**	**6,877,000**	**16,265,700**

1. Includes parabolic trough, power tower, dish engine, and concentrating PV

Source: WGA Solar Task Force – Central Solar Working Group, Draft Report, July 2005 and confirmed via interview with, Mark Mehos, NREL, February 2006.

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Solar thermal electric technologies will eventually use thermal storage or natural gas hybrids that can result in capacity factors of > 40%.

Advantages

- No emissions, except when combined with natural gas capability in hybrid configurations.
- Potential high coincidence between peak output and peak demand.
- Strong potential in Arizona due to abundance of direct sunlight.
- Large scale relative to photovoltaics, with plant size ranging from 25 kW (dish Stirling) to 50 MW or more (dish and trough systems).[1]
- Uses some of the same technologies as conventional central power plants (steam turbine generators), accelerating the learning curve.
- The use of thermal storage or natural gas hybrids (using gas turbines) eventually will soon result in capacity factors >40%.

Disadvantages

- High first costs relative to competing technologies such as simple and combined cycle gas turbines
- Transmission/distribution systems need to be developed to transport power from good solar sites to load centers
- Large land requirements (about 5 acres per MW for trough or dish Stirling)
- Central station solar applications (such as trough, Power tower, and in some cases dish engines) compete with wholesale electricity costs. PV technologies by contrast generally compete with retail power at the end use.

1. Tower systems have the potential for up to 200MW in 10 years

Parabolic trough costs need to further decline, and solar dish engine costs need to decline from the present hand-built level of production.

R&D	Demonstration	Market Entry	Market Penetration	Market Maturity
	Power Tower Dish Engine	Parabolic Trough		

Development Issue	Description
Performance	• Trough: Heat Collection Element: new coatings and better reliability. Improve collector/mirror designs. Advanced heat transfer fluids that do not degrade at 400°C and that have a low freezing point and viscosity. Temperature increase to 500°C for storage applications and tower technology to 650°C. • Stirling engine reliability improvements and enhancements continue at Sandia
Land Use Implications	• Requires large land areas of 5 acres per MW for trough and dish Stirling • Emissions are zero unless combined with natural gas, minimizing impacts on local communities and climate
Noise and Visual Impacts	• Visual impacts can be great, with large land areas covered with reflective surfaces • Noise can be associated with steam turbines and generators, but these are centrally located which helps minimize noise at the plant perimeter
Storage	• Not expected to be economically viable for troughs until after 2010. Spain is installing a 50 MW trough unit with 6 hrs of storage that is closing financing in 2006. Should be operational in 2007. • Now use two storage tanks with HX/oil. Goal in future is one tank and to put molten salt in the field.

Source: NCI based on interview with National Renewable Energy Laboratory, February 2006 and input from Bob Liden, Executive VP and General Manager, Stirling Energy Systems, September 19, 2006.

NAVIGANT CONSULTING

Dish engine technologies, in small deployment volumes, are costly and their performance in large power plant applications is unproven.

Solar Dish Technology and Resource Availability

- Solar potential in AZ is high, but large-scale field experience is not yet proven
- Several experimental dish/Stirling units operating, each ~10-25 kW in size with 38 foot diameter dish. Active development of multi 100 MW systems.
- System efficiencies of nearly 30% have been achieved, higher than either trough or tower systems. Typical efficiencies are around 22 - 24%. Reliability issues.
- Use very little water – less than 1% of the water required for steam-driven plants
- Stirling Energy Systems (SES) in Phoenix AZ is the key remaining U.S. player, with six units operating in demonstration mode at Sandia. There is also one 25 kW system in Johannesburg purchased by ESKOM, and a 25 kW system at University of NV at Las Vegas.
  - Have PPA with Southern California Edison (Edison International) for 500 MW with 350 MW option. Plant will be in Mohave Desert and PPA with San Diego Gas & Electric (Sempra) for 300 MW with 600 MW option
  - Total potential is 1,750 MW (70,000 units) to aid with mass production that is needed to reduce cost

Economic Issues

- High efficiency is offset by small system size, which results in high capital costs. 2006 installed cost estimated at $8,000/kW without mass production.[1]
- Economic data are not publicized for dishes, but SES has provided some ballpark figures based on their experience and work with equipment suppliers.

[1] Source: NCI based on interview with National Renewable Energy Laboratory, February 2006; the Wall Street Journal, *Solar's Day in the Sun*, November 17, 2005; input from Bob Liden, Executive VP and General Manager, Stirling Energy Systems, September 19, 2006.

Reliability improvements and significant cost reductions are needed for dish engine systems to be viable.

Advantages

- Smaller unit sizes can be used for distributed generation (<75kW) where it would compete with retail electricity improving its potential economic attractiveness.
- Uses small Stirling or Brayton cycle engine for power generation, both of which can be hybridized with natural gas to extend operation.
- Higher temperature (720°C) than trough technology.
- Currently offers the highest solar to electric efficiency.
- Technology has the support of the Western Governors' Association

Challenges

- Stirling engines demonstrated, but not yet commercialized
- Reliability and performance improvements still needed:
  - Dish: increase mirror area
  - Engine: improve generators, seals, and Δt
- O&M costs are unknown for large deployment of systems and overall economics are not solidly established
- Small system size limits potential for decreased costs beyond economies of production
- Initial capital costs are estimated at $8,000/kW.

Sources: NCI based on Design News, *Sun Rises on Solar*, January 9, 2006 and input from Bob Liden, Executive VP and General Manager, Stirling Energy Systems, September 19, 2006.

NAVIGANT CONSULTING

Solar dish Stirling economics are still somewhat unproven. Below are some estimates of their economics.

	Solar Dish Stirling Economic Assumptions for Given Year of Installation			
	2006	**2010**	**2020**	**2025**
Plant Capacity (MW/year)	15	15	15	15
Total installed cost ($/kW)[1]	$6,000	$4,000	$2,000	$1,300
Non-Fuel Fixed O&M ($/kW-yr)[3]	$200	$80	$20	$15
Capacity Factor (%) – High Insolation[2]	23%	23%	23%	23%
Project Life (yrs)	25	25	25	25
CO_2 (lb/kWh)	No Air Emissions			
NOx (lb/kWh)				
SOx (lb/kWh)				

1. SES cost estimates assume close to 750 MW build rate to achieve the low cost pricing. The performance reliability of their product has not been verified, so NCI has not used SES claims.
2. 23% is for Phoenix
3. Includes items such as the receiver engine and gas working fluid costs

Source: Navigant Consulting, Inc. estimate based on interviews with NREL and Herb Hayden, APS February 2006.

Note: 25 kW dish installations (without 15 MW volume production) would result in installed costs of $8,000/kW today.

NAVIGANT CONSULTING

Stirling Energy Systems (SES) provided cost projections to NCI. Below are SES projections assuming scale up targets are met.

	Solar Dish Stirling Economic Assumptions for Given Year of Installation			
	2006	2010	2020	2025
Plant Capacity (MW/year)	15	250	250	250
Total installed cost ($/kW)	$6,000	$2,000	$1,500	$1,300
Non-Fuel Fixed O&M ($/kW-yr)[2]	$125	$8	$8	$8
Capacity Factor (%) – High Insolation[1]	25%	25%	25%	25%
Project Life (yrs)	35	35	35	35
CO_2 (lb/kWh)	No Air Emissions			
NOx (lb/kWh)				
SOx (lb/kWh)				

1. 25% is for Phoenix
2. Includes items such as the receiver engine and gas working fluid costs

Source: Bob Liden, Executive VP and General Manager, Stirling Energy Systems, September 19, 2006.

NAVIGANT CONSULTING

Parabolic trough is potentially an attractive renewable energy option for AZ applications.

Technology and Resource Availability

- Parabolic trough technology is the only solar thermal technology with years of operating commercial units. Expected operating life is 30 years. Existing plants are often natural gas hybrids, using gas fired boilers to supplement solar energy.
- 354 MW of trough technology has been operating in CA since mid-1980s; 64 MW Solargenix trough installations are planned in NV with ribbon cutting February 2006, and a 50MW trough plants with 6 hr storage in Spain by end of 2007. Spain unit is currently closing financing.
- Parabolic trough capacity factors are 25-29% without storage; 38-42% expected with 6 hours of storage by 2010 as molten salt storage technology is advanced.
- Efficiency is 14%, rising to 16% over the next 10 years. Optimum project size is 50 MW, but 30-80 MWe are commercialized.

Economic Issues

- The LCOE for parabolic trough is currently 10-15¢/kWh (with incentives), nearly 2-3x the cost of wholesale power.
- Many projects get stalled in planning due to the large capital outlay ($3,900/kW no storage). This cost is expected to drop to $3,200/kW by 2020 with 6 hours of storage.
- Advances in storage technology will improve economics by increasing the capacity factor; similarly, gas turbine hybrid systems can also extend operating hours.

Parabolic trough is technically viable, and field performance has been proven.

Advantages

- Most advanced and proven solar thermal technology
- North-South tracking system is less complex than the 2-axis movement required by power tower and dish engine
- Long operating life (30 years)
- Potential for hybrid with natural gas improves economics and dispatchability
- The LCOE will decline over time as storage capability extends operating hours
- Technology has the support of the Western Governors' Association

Challenges

- High initial capital cost today at $3,800/kW without storage
- Transmission cost of bringing power into load centers may be high.
  - Costs of extending transmission lines $500,000 - $1 million per mile for 230 – 500 kV lines
- Unresolved heat storage issues. System may need to reach higher temperatures (450-500˚C) to make storage practical
- Heat storage capability will increase system cost by ~$350-400/kW, but improvements in the structure, receiver, and reflector costs will help bring overall system price down.
- Historically have used wet cooling tower for cooling. Cooling tower make-up represents 90% of raw water consumption. Steam cycle make-up 8% and mirror washing 2%. Availability of water can be an issue.
  - 2.8m^3 per MWh[1]
- 5 acres of land for each MW (no storage)[1]

1. Arizona Utility Estimates, September 2006.

The capacity factor for solar parabolic trough could increase dramatically with the introduction of storage by 2010.

	Solar Parabolic Trough Economic Assumptions for Given Year of Installation (2006$)			
	2006	**2010**	**2020**	**2025**
Plant Capacity (MW/yr)	50	50	50	50
Total Installed Cost ($/kW)[1]	$3,900	$4,500	$3,200	$2,600
Non-Fuel Fixed O&M ($/kW-yr)	$60	$40	$35	$35
Capacity Factor (%) – Phoenix[2]	27%	38%[2]	38%[2]	38%[2]
Project Life (yrs)	30	30	30	30
CO_2 (lb/kWh)	No air emissions			
NOx (lb/kWh)				
SOx (lb/kWh)				

1. A 50 MW system with 6 hrs of storage is being installed in Spain and should be operational by the end of 2007. Increasing the plant capacity to 100 MW would reduce costs 10%.
2. Assumes 6 hours of molten salt storage starting in 2010.

Source: Navigant Consulting, Inc. estimates based on Sargent and Lundy, "Assessment of Parabolic Trough and Power Tower Solar Technology Cost and Performance Forecasts," 2003 and interview with Mark Mehos and Hank Price, NREL, February 2006.

The capability of Tower technology could be enhanced with storage.

Power Tower Technology and Resource Availability

- The biggest technical issue is the molten salt receiver.
  - The molten salt receiver for Solar Two was developed by Boeing's Rocketdyne division.
  - Rocketdyne was sold to Pratt and Whitney (part of United Technologies).
  - Rocketdyne is currently working with ESKOM on the development of a 100MW tower project in South Africa
  - Sener had developed a design for the Solar Tres plant
- The PS 10 system (11 MW Tower system in Spain) has an estimated capacity factor of 20%. This could be increased to 75% with a molten salt storage system.
- Molten salt systems require large amounts of energy for heating because sodium nitrate freezes at ~580°F. Solar Two was not a net producer of electricity because of its heating power requirements.
- Molten salt can be heated to 1000°F, the utility standard steam temperature.
- Land use for the PS10 plant is 11 acres per MW with no storage.

Economic Issues

- Lack of commercial history makes raising capital difficult.
- Advances in molten salt receiver and storage will increase the capacity factor and decrease the LCOE
- Large plant sizes (100 to 200 MW) can allow for economies of scale to reduce costs.

Switching to molten salt as a working fluid can increase the attractiveness of Power Tower systems.

Advantages

- Higher temperature working fluid (~1000°F) than trough and Dish engines allows for higher efficiencies.
- If steam used as working fluid, less heat exchange losses compared to trough
- Higher efficiency storage than trough
  - Working fluid is at a higher temperature and is also a storage medium
- Heliostats can be for astronomical observation at night. This is done with Solar Two.
- Tower systems have potential for up to 12 hours of storage with molten salt, resulting in 65%+ capacity factors.
- Large plant sizes can allow for economies of scale to reduce costs. This is not as feasible for Dish engine systems.

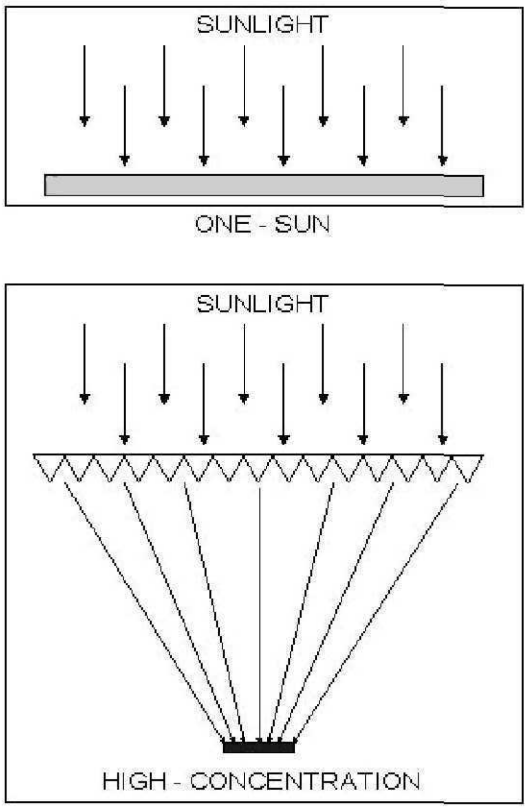
Disadvantages

- Tower technology demonstrated, but not yet commercialized in comparison to trough
- Focal efficiency is worse than trough because of central design. Significant losses in winter months.
- O&M costs are unknown and overall economics are not solidly established. Trough systems have established costs.
- Two axis tracking for heliostats requires more complex controls than trough's single axis system.
- Water requirements for power block reduces amount of available land for siting
- Central generation design requires longer construction times compared to Dish engine systems.
- Tower systems require extremely flat land (less than 1% slope). Dish systems do not have this requirement.

Power Tower economics have potential, but there are significant near-term development risks, so more detailed analysis was not undertaken.

NAVIGANT CONSULTING

Concentrator photovoltaics (CPV) use lenses or reflective collectors to focus solar energy (typically > 100 suns) on a reduced area of solar cell material that is more efficient.



From www.amonix.com

Arizona Public Service photo: Prescott 35 kW, dual axis tracking system.

NAVIGANT CONSULTING

CPV is an early stage technology that holds the promise of higher efficiency PV in the 2 kW-5 MW size range.

Technology and Resource Availability

- CPV technology is in the prototype stage and under development at NREL, several universities, and private companies In 2004, 1 MW was installed, but Australia will be installing 150 MW in the next few years.
- Need to demonstrate performance reliability and 20 yr life to be competitive.
- Amonix, key U.S. player, claims to need minimum production of 10 MW to be competitive[1].
  - Arizona Public Service (APS) and Amonix have worked together since 1995 and have >600 kW operating in AZ with 26% efficient cells/250x solar concentration
  - Amonix/Guascor JV to build a 10 MW/year assembly plant in Spain
- Sharp and Daido (Japan); Isophoton (Spain); Concentrix Solar (Germany); Concentrating Technologies and Pyron (US) using III-V multi-junction solar cells. Amonix and Solar Systems are testing III-V cells which are best for higher levels of concentration.

Economic Issues

- At production volumes of 10 MW/yr, silicon CPV could drop below $3,000/kW.

Sources: Fraunhofer Institute, *Concentration PV for Highest Efficiencies and Cost Reduction*, June 2005; Boeing Spectrolab interview, Aug 2004 and Amonix interview Feb. 2006; Fraunhofer Institute for Solar Energy Systems, June 2004; "The Role of CSP in Filling APS' Future Solar Energy Needs", presentation by Herb Hayden, May 2005. [1] Interview with Amonix, February 2006.

CPV offers interesting advantages, but has technical challenges to overcome.

Advantages

- There is good availability of direct solar resources in Arizona
- CPV systems increase the power output while reducing cell area requirements
- Solar cell efficiency increases under concentrated light
- Because smaller PV areas are needed, smaller cells can be used which are less expensive to produce than large-area cells
- MW sizes are possible using PV concentrators of up to 1,000 suns
- Tracking the sun (with dual axis trackers) increases the energy produced (in kWhs) per kW compared with fixed flat plate

Challenges

- Concentrating optical systems are more expensive than the simple glass or laminates used for flat plate PV
- CPV systems have to track the sun daily throughout the year, which requires tracking mechanisms and more precise controls
- Concentrators cannot focus diffuse light, which represents ~20% of available solar radiation. Flat plate PV utilizes both direct and diffuse light
- Concentrated light can overheat PV cells, reducing their efficiency. As a result, CPV solar cells have to be kept cool, potentially adding to the cost. Highly conductive materials such as copper can be placed behind the cells, or air cooling can be used
- 10 acres per MW for Amonix technology

Source: Navigant Consulting, Inc. based on Renewable Energy World, *Concentrating PV Prepares for Action*, Volume 8, September –October 2005 Issue and interview with NREL, February 2006.

Installed system costs for concentrating PV are high due to small production volumes.

	Concentrator PV (Amonix) Economic Assumptions for Given Year of Installation (2006$)			
	2006	2010	2020	2025
Plant Capacity (MW/yr)	15	50	100	100
Total Installed Cost ($/kW)	$5,000	$4,000	$2,500	$2,100
Non-Fuel Fixed O&M ($/kW-yr)	$45	$35	$10	$8
Capacity Factor (%) – Phoenix	23%	23%	23%	23%
Project Life (yrs)	25	25	25	25
CO2 (lb/kWh)	No air emissions			
NOx (lb/kWh)				
SOx (lb/kWh)				

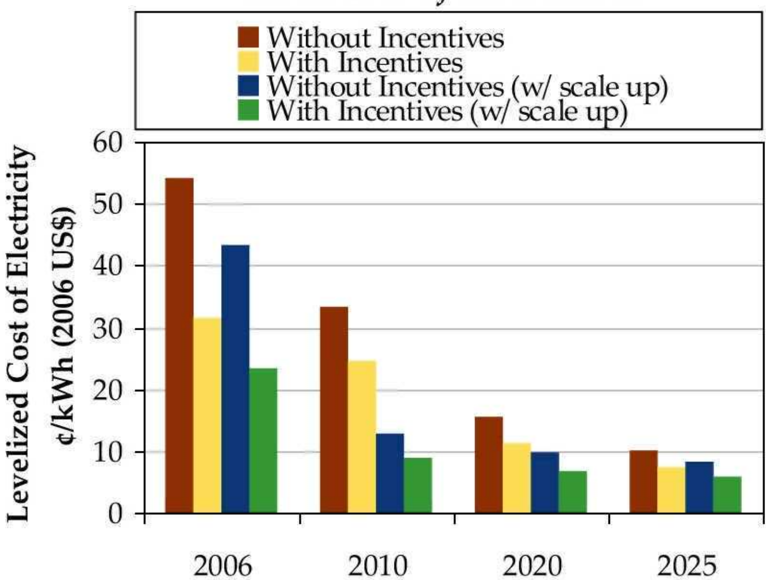
Source: Navigant Consulting, Inc. estimates based on interview with Amonix, February 2006 for installed costs, capacity factors and O&M. Capacity factors also based on interviews with NREL and APS February 2006.

NAVIGANT CONSULTING

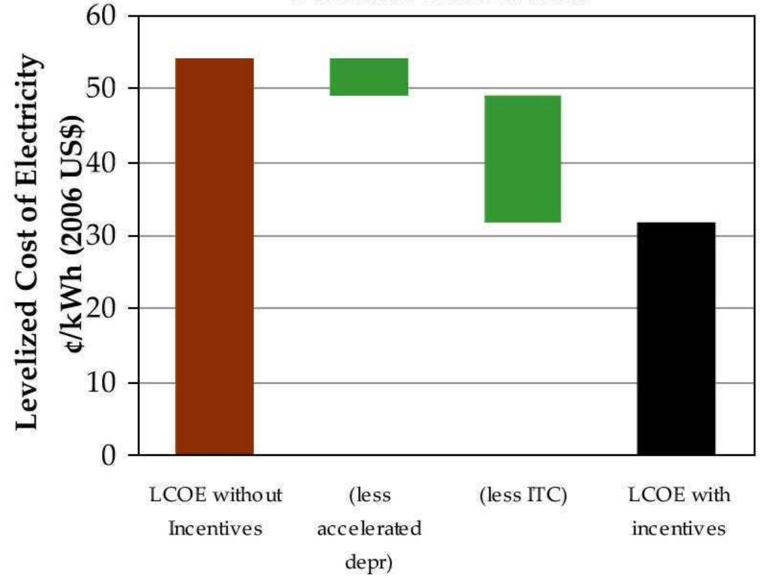
Dish Engine economics are currently expensive, but future expectations are that economics will improve with production volumes.

AZ Levelized Cost of Electricity for Dish Engine, Developer Financed

With and Without Federal Incentives for Given Year of Installation



With Incentives – 2006 Installation, Phoenix Insolation



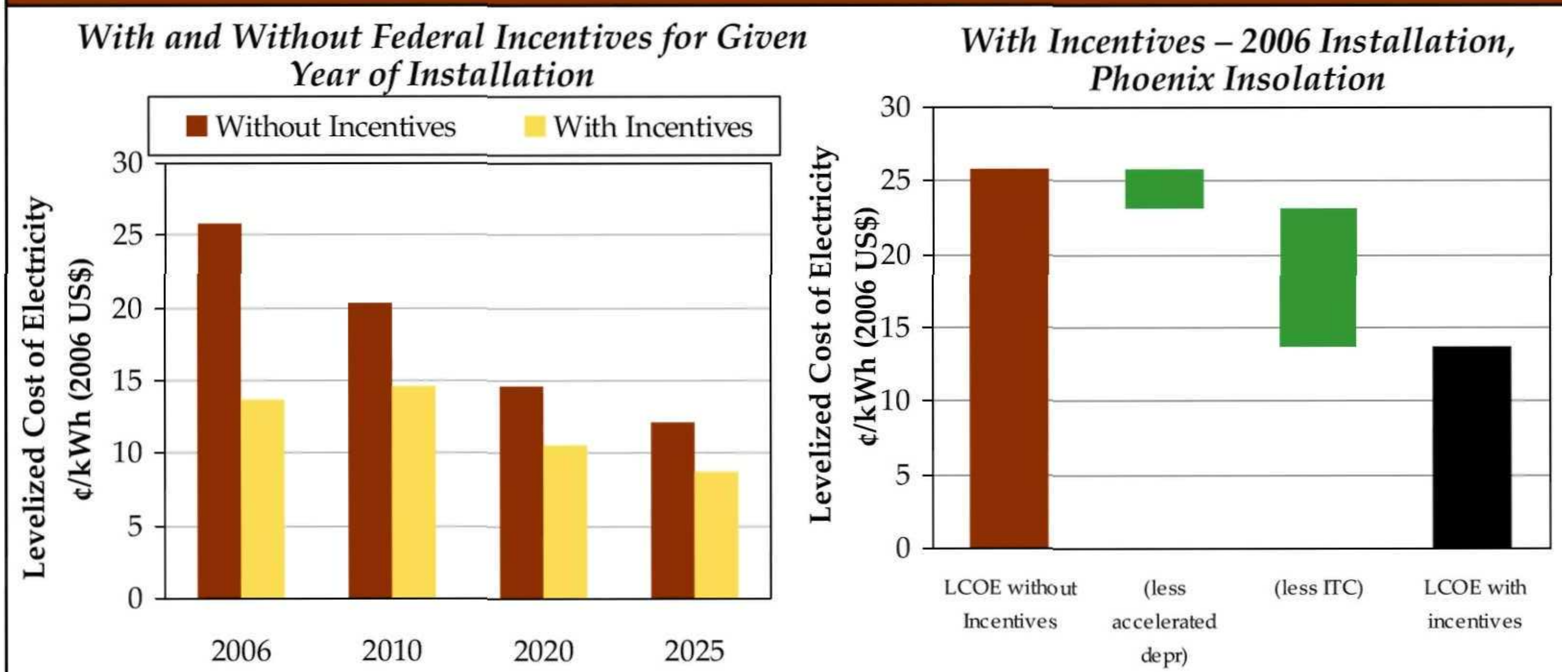
Key assumptions (without incentives): Debt equity ratio: 55%:45%, cost of equity = 15%, cost of debt = 8%, Marginal federal + state income tax = 41%. Insurance = 0.5%, Depreciation under Modified Accelerated Cost Recovery System (MACRS): Depreciation period considered is 15 years. Loan period = 10 years. Project economic life = 25 years. Property tax rate of $11.70/$100 of assessed value.

Key assumptions (with incentives): Accelerated depreciation under MACRS 5 year schedule. Federal investment tax credit = 10% of **total installed** cost in year 1 after 2007. Note currently the incentive level is 30%, but this is due to expire in 2007. Source: NCI analysis assuming data from NREL without incentives and from Bob Liden, Executive VP, Stirling Energy Systems, September 19, 2006.

NAVIGANT CONSULTING

Assuming only conservative Federal incentives, trough technology may become attractive after 2010.

AZ Levelized Cost of Electricity for Solar Parabolic Trough, Developer Financed



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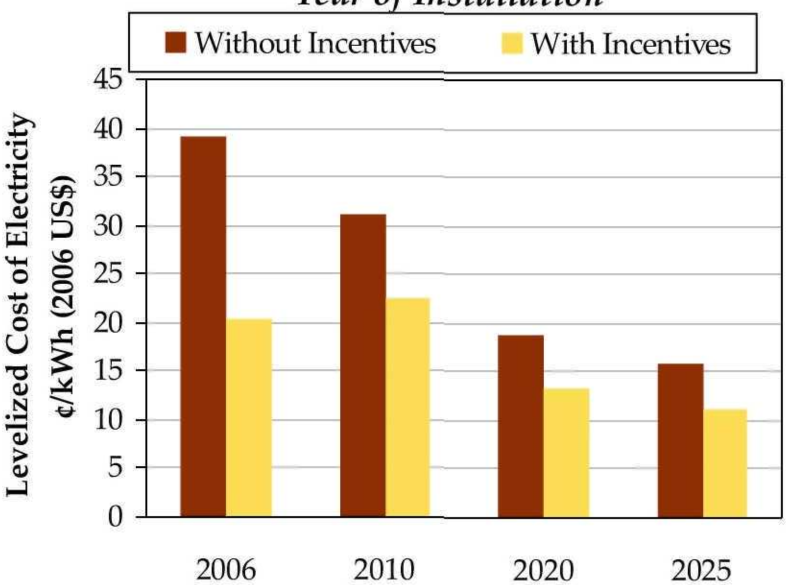
NAVIGANT CONSULTING

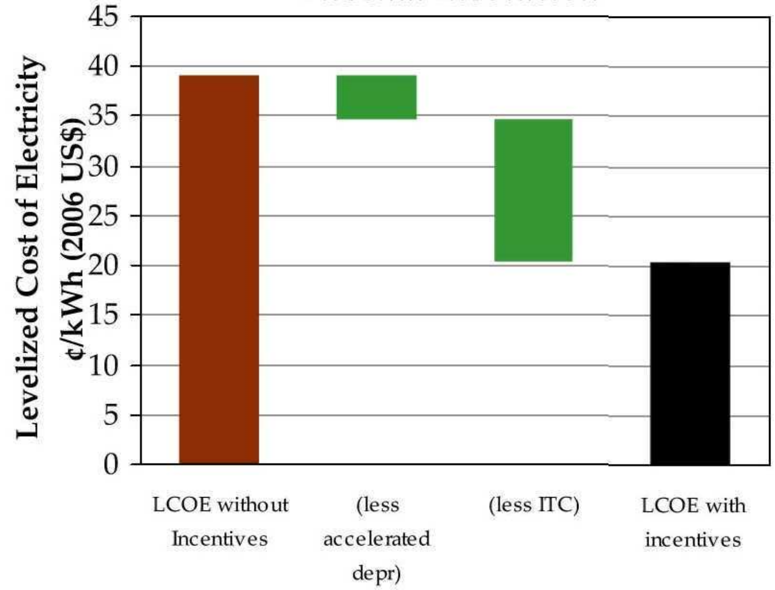
If one assumes the minimum amount of Federal incentives, the LCOE for concentrating PV may become attractive after 2010.

LCOE for Concentrating PV (Amonix), Developer Financed Conservative Incentive Assumptions

With and Without Federal Incentives for Given Year of Installation



With Incentives – 2006 Installation, Phoenix Insolation



Key assumptions (without incentives): Debt equity ratio: 55%:45%, cost of equity = 15%, cost of debt = 8%, Marginal federal + state income tax = 41%. Insurance = 0.5%, Loan period = 10 years. Project economic life = 25 years. Property tax rate of $11.70/$100 of assessed value. Depreciation under Modified Accelerated Cost Recovery System (MACRS): Depreciation period considered is 15 years. Key assumptions (with incentives): Accelerated depreciation under Modified Accelerated Cost Recovery System (MACRS) 5 year schedule. Federal investment tax credit = 10% of **total installed** cost in year 1. Note currently the incentive level is 30%, but this is due to expire in 2007. Source: NCI analysis.

NAVIGANT CONSULTING

The Solar Chimney is another concept being developed, but the technology is still in early stages of development.

Solar Chimney

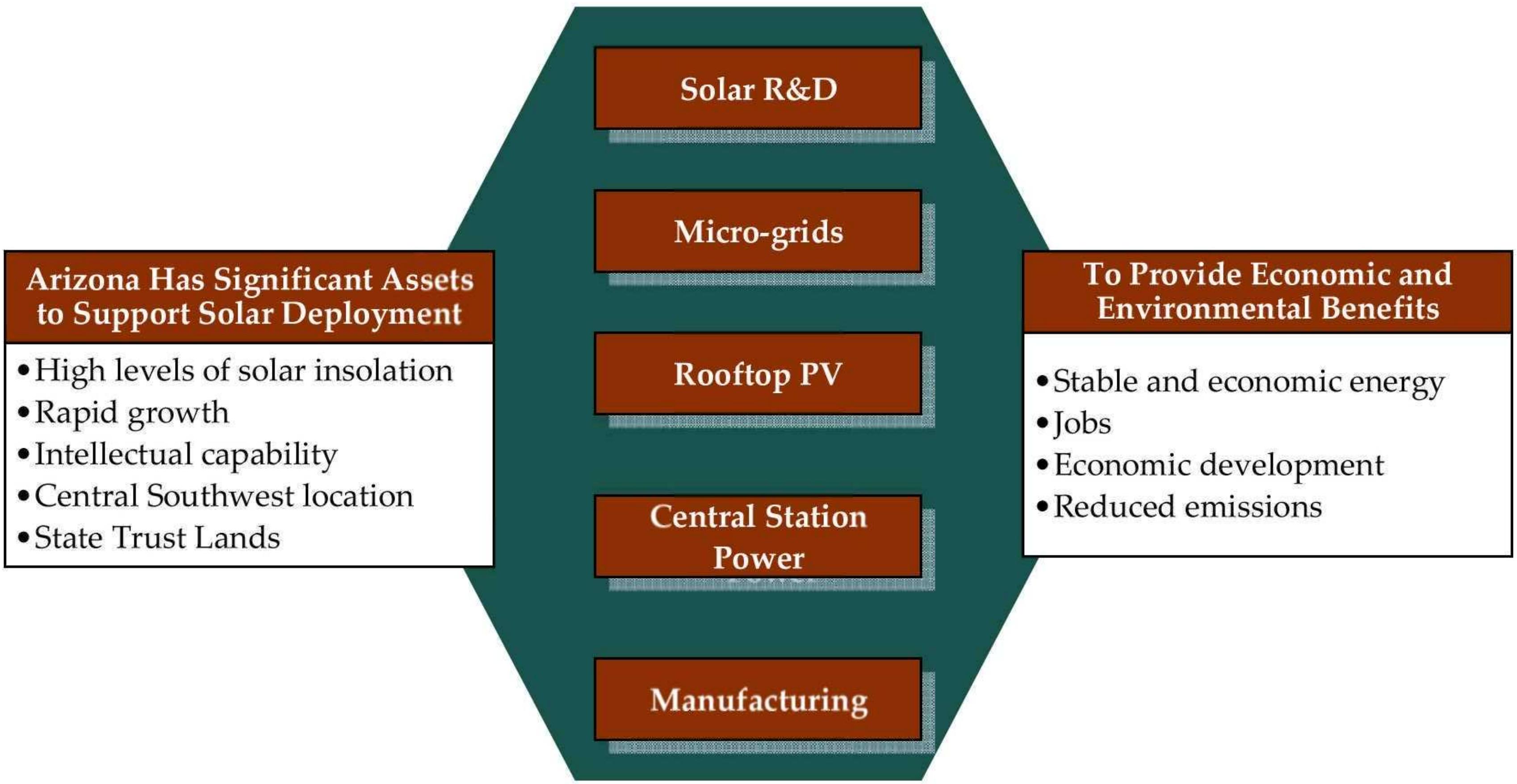
- Produces a high capacity factor for a solar technology
- Simple principal of operation
- Remains unproven at large scale (200 MW)
- Limited experience building a tower this tall
- Would use "new" wind turbine technology (i.e., different from freestanding wind turbines) that are being custom designed and built for this application
  - While new, the turbines are based on well-proven, pressure-stage technology
- Land intensive relative to other renewable technologies
- Resistance to severe weather (high winds, tornados) and other natural disasters need to be tested
- Requires large scale-up for the technology to work and be economically attractive

The sun's radiation is used to heat a large body of air under an expansive collector zone, which is then forced by the laws of physics (hot air rises) to move as a hot wind through large turbines to generate electricity. A Solar Tower power station will create the conditions to cause hot wind to flow continuously through 32 x 6.25MW pressure staged turbines to generate electricity

NAVIGANT CONSULTING

Table of Contents

Arizona's assets could support multiple opportunities for developing solar-related business in the state.



NAVIGANT CONSULTING

The STAR facility is renown globally as a unique and excellent solar test and research center. AZ should capitalize on this unique position.

APS Solar Energy

Solar Test & Research Center (STAR)

- In Tempe and serves needs of APS, manufacturers, scientists, engineers, & students
- Largest of its kind in the world and excellent reputation

Installations

PV – 5 MW
West Wetlands PV – 96 kW
Saguaro Trough – 1 MW
Prescott College – 10 kW
Cochise College Solar Heating & Cooling – 200 kW

Solar Energy Customer Program

Project Sol: donated 5 2kW solar systems to education and performance monitored

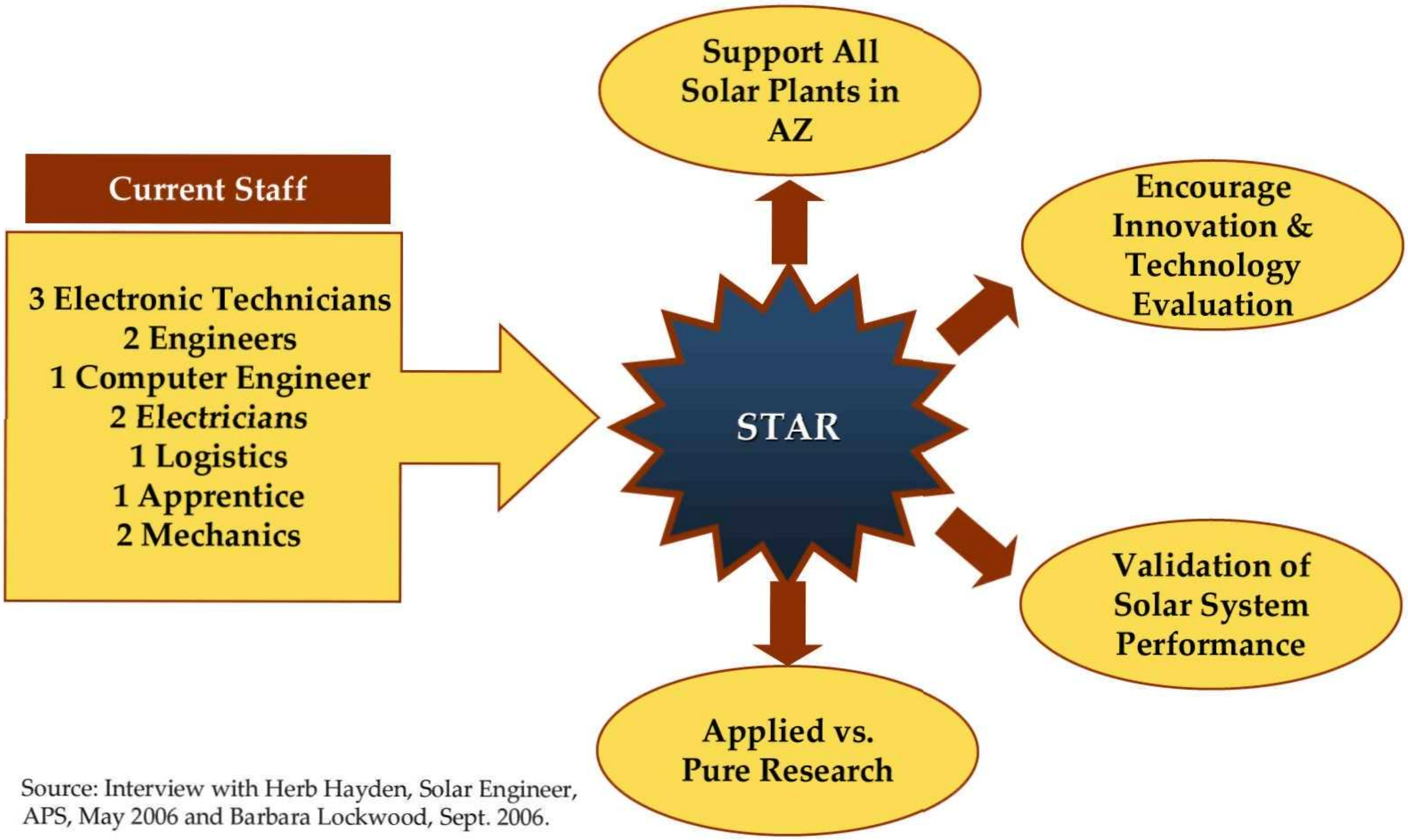
Solar Partners Incentive Program: \$3/W for residential and \$2.50/W for commercial. Cap of \$500k per customer per year

Voluntary contributions where customers contribute \$2.64 for 15 kWh blocks per month

Green: complete. Blue: under construction

Source: Herb Hayden, Barbara Lockwood, Peter Johnston, APS, June and Sept. 2006.

STAR funding has decreased in recent years. New sources of funding should be explored.



Source: Interview with Herb Hayden, Solar Engineer, APS, May 2006 and Barbara Lockwood, Sept. 2006.

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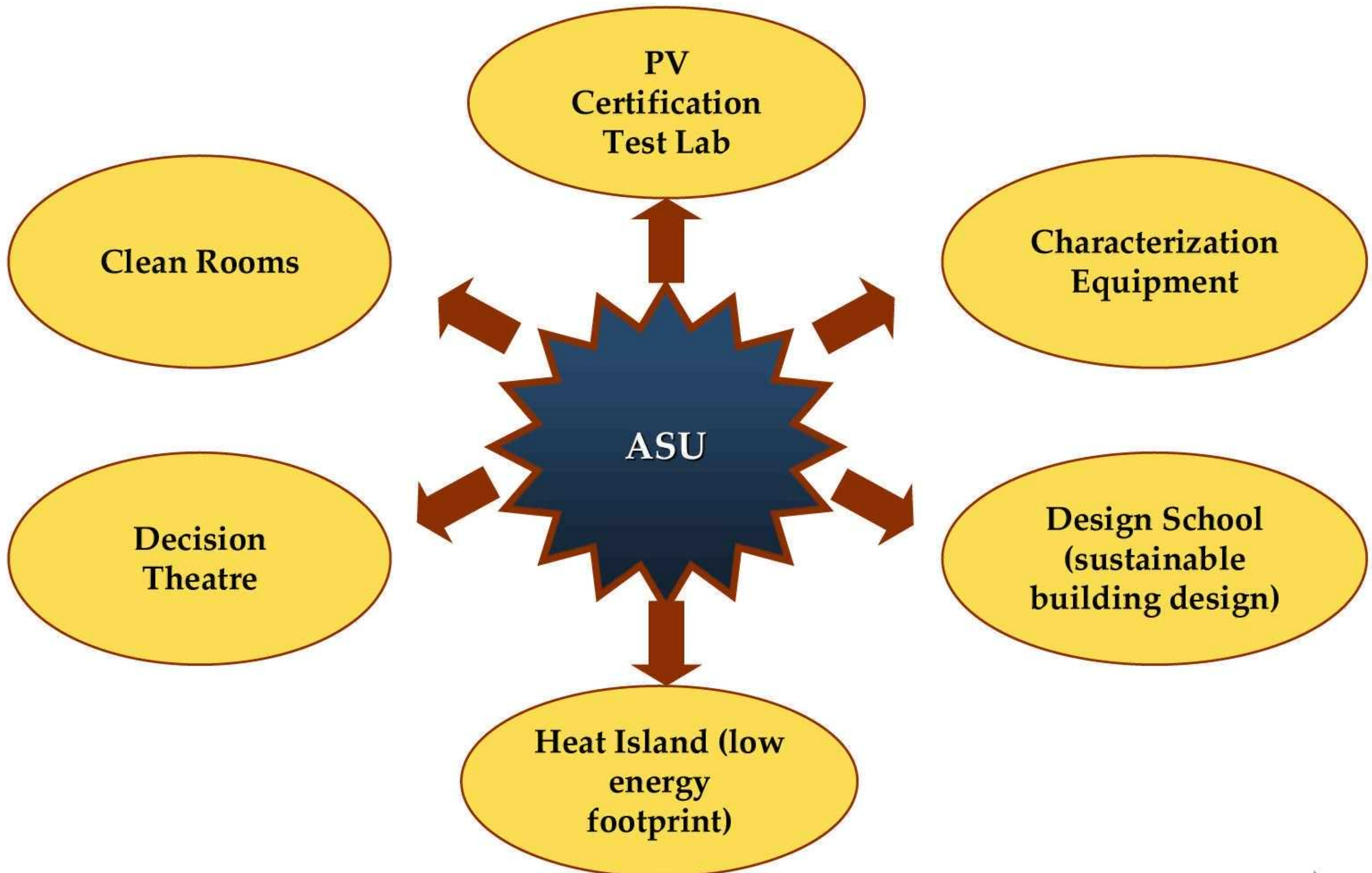
ASU capabilities may need to be re-invigorated to support a large solar initiative in the state.



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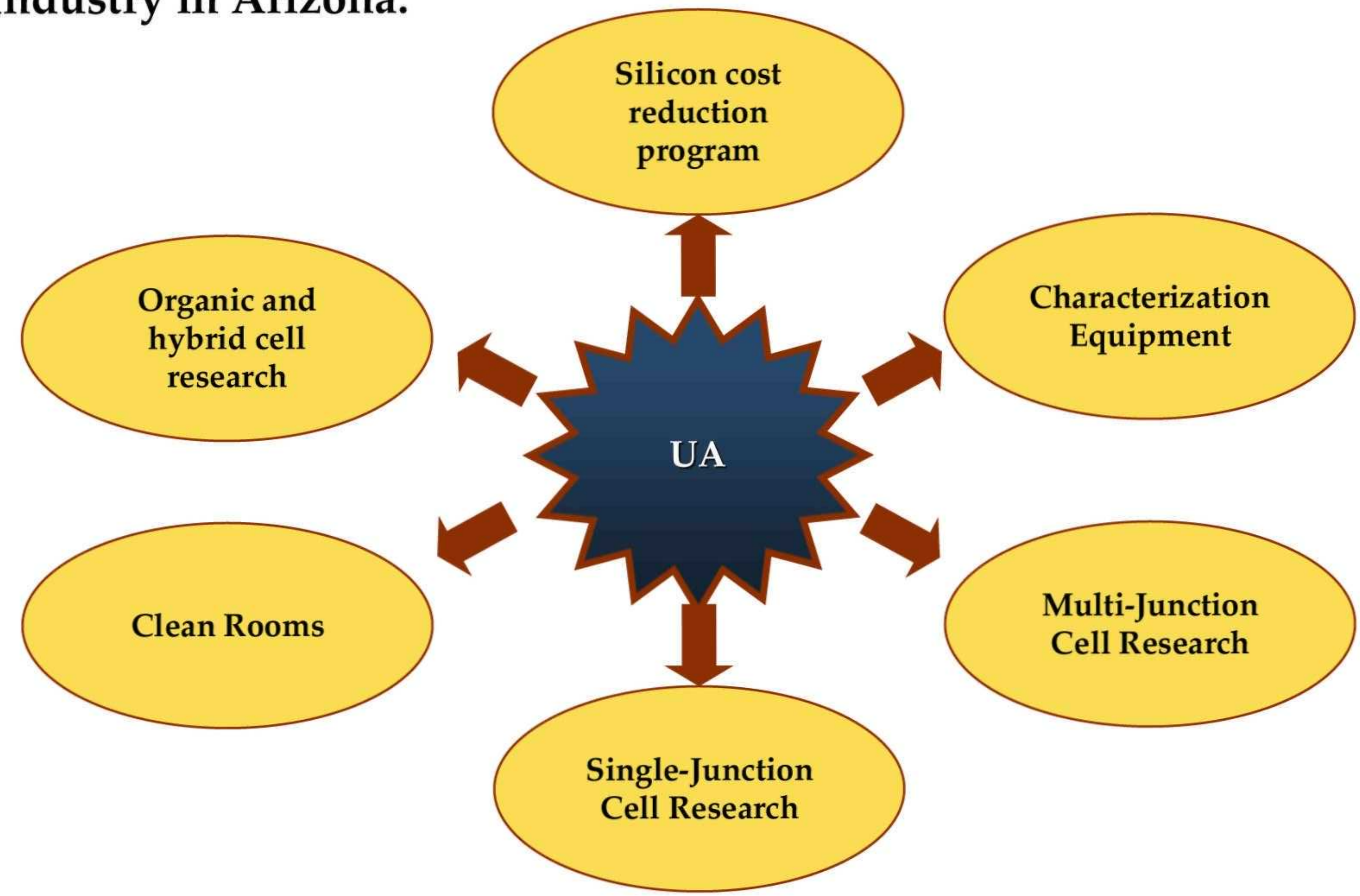
UA has several research programs and facilities to help grow the solar industry in Arizona.



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Opportunities » AZ University Coursework

Solar-Related Coursework Offered by Arizona's Higher Education Institutes

University	Course Name	Field
Arizona State University	Environmental Rating Systems for Buildings	Architecture
	Applied Photovoltaics	Engineering
	Building Energy Analysis	Architecture/Engineering
	Energy Analysis and Techniques	Architecture/Engineering
	Environmental Control Systems	Architecture
	Energy Conversion and Applications	Engineering
Northern Arizona University	Energy, Ecology and You	Public Awareness
	Heat Transfer	Engineering
	Solar Engineering Analysis and Design	Engineering
	Energy Environment	Engineering
	Thermodynamics	Engineering
University of Arizona	Silicon Processing	Engineering
	Computer Energy Analysis	Architecture
	Advanced Computer Energy Analysis	Architecture
	Solar Utilization in the Built Environment	Architecture
Chandler-Gilbert Community College	Solar Energy	Public Awareness
Yavapai College	Solar Energy Systems	Construction
	Energy Efficient Buildings and Design	Construction
Coconino Community College	Solar Home Design	Construction
	Photovoltaics and Wind Power	Construction
Arizona State University	MS in Technology with a concentration in Environmental Technology Management	Engineering
Coconino Community College	Alternative Energy	Construction

NAVIGANT CONSULTING

Microgrids integrate loads and DERs in self-contained energy systems that can operate in parallel with the larger grid.

Microgrid Definition

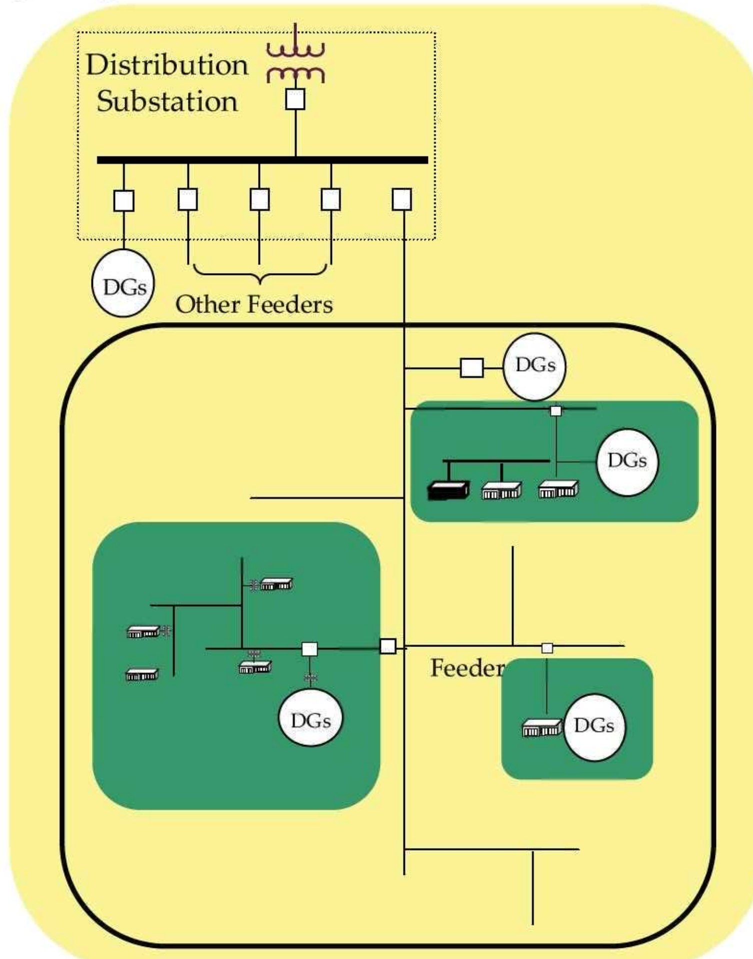
General Definition

A microgrid is an integrated energy system consisting of interconnected loads and distributed energy resources which as an integrated system can operate in parallel with the grid or in an intentional island mode.

Key Defining Characteristics

The integrated distributed energy resources are capable of providing sufficient and continuous energy to a significant portion of the internal demand. The microgrid possesses independent controls and can island and reconnect with minimal service disruption.

- **Flexibility** in how the power delivery system is configured and operated
- **Optimization** of a large network of load, local Distributed Energy Resources and the broader power system



The microgrid concept supports a compelling value proposition if technology and regulatory barriers can be overcome.

Microgrid Opportunities

- Microgrids can deliver several value propositions:
  - Reduced cost
  - Increased reliability & security
  - Green power
  - Service differentiation
  - Power system optimization.
- Market opportunities are driven primarily by reduction in energy cost and volatility
- Larger microgrids may offer the greatest opportunity for cost savings and other value propositions
- Market conditions and scenarios will dictate which vale propositions are most attractive to key stakeholders

Microgrid Challenges

- Current technology may meet many functional requirements, but overall cost and performance are insufficient for envisioned microgrids
- Complex value propositions beyond energy cost reduction, as well as larger microgrids, pose greater technology challenges
- Key technical challenges include:
  - System integration
  - Standards
  - Power electronics
  - Energy storage
  - Communications and control
- Overcoming regulatory barriers such as ownership and operating rights is critical.

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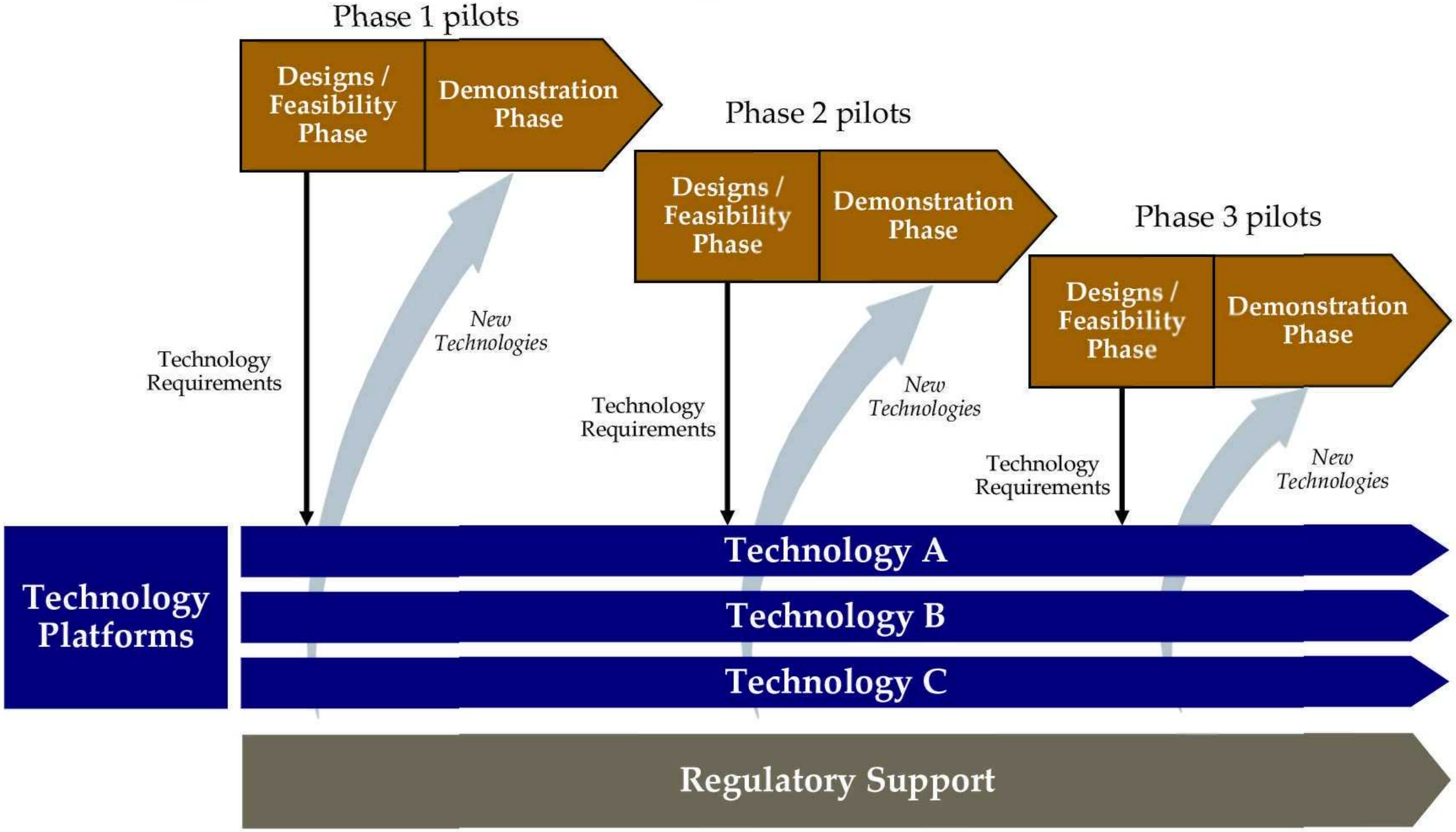
A systematic program of pilots that design and demonstrate technology and regulatory models could be part of AZ R&D and roadmap.



While Arizona has significant assets to support a solar R&D business, investment will be required to compete with established entities.

Strengths/Assets

- STAR
- PV certification center
- University facilities & professors
- Funds from RES?

Opportunities

- DOE $170 million solar initiative, needs matching funds
- Significant R&D is required throughout entire value chain

Weaknesses

- Limited activity – primarily demonstration and testing as opposed to research
- Need to establish "Center(s) of Excellence"

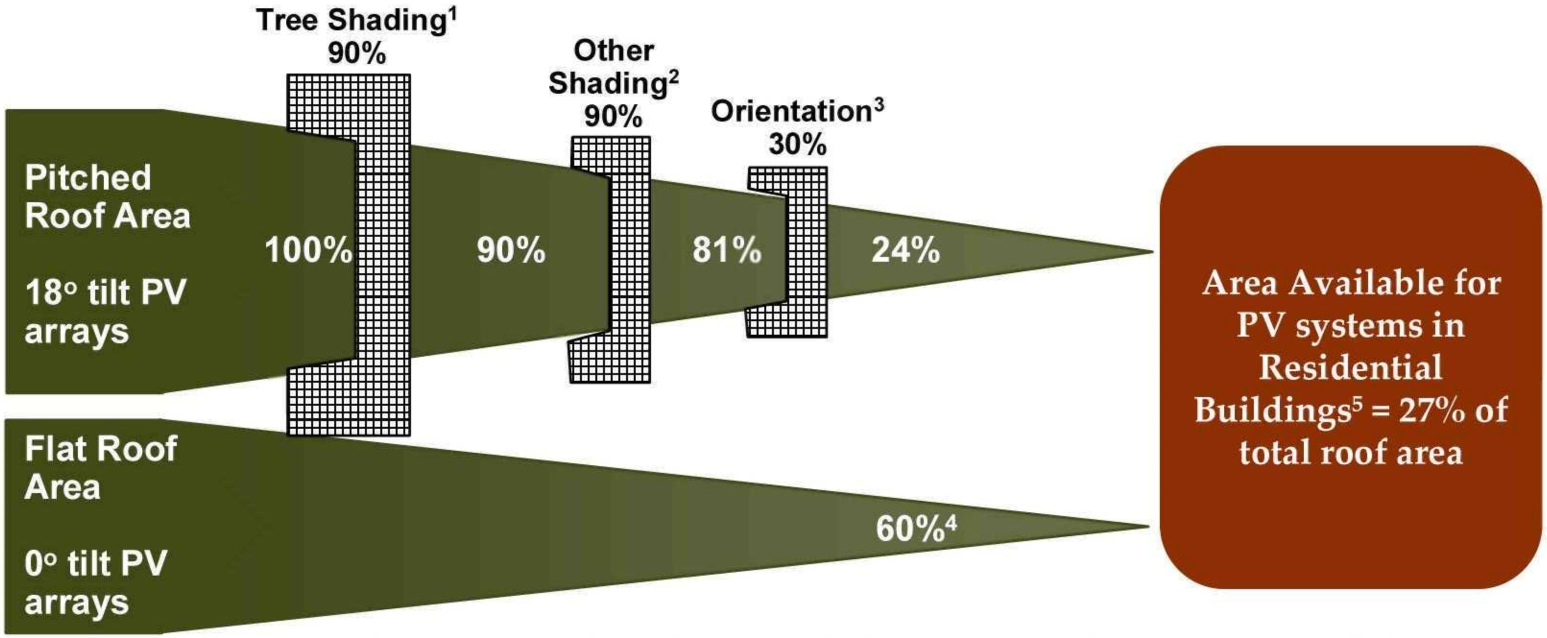
Threats

- Established competition: NREL, University of California, Stanford, Ohio (Wright Center of Innovation)
- Need to make investments soon

DOE's $ 170 million solar initiative is a major opportunity to leverage Arizona investments to develop a capability and national leadership

NAVIGANT CONSULTING

The roof space available on *residential* buildings for PV installations is around 27% of total roof area.



1. Roof area available due to tree shading is around 90% for single homes and higher at 95% for townhouses Townhomes and other residential buildings are often higher and thus there would be less shading than for a detached house. Closely packed homes in high density neighborhoods allow little room for large trees to grow and shade roofs, compared to larger homes in low density neighborhoods.
2. Other shading may be due to chimneys, vent stacks and other roof obstructions.
3. Based on assumptions made for single homes, which account for 70% of the building stock. Assume that orientations from southeast clockwise around to west are appropriate for PV installations. For gable ended roofs with one long ridge line, assume that one of the pitched surfaces will face in the proper direction for 75% of the residences. If each surface is half the roof, 38% of the roof area can accommodate PV arrays. For hip roof buildings, one of four roof area will be facing in the right direction, or 25% of the roof area. The average of 38% and 25% is around 30%, which is what is assumed as the percentage of roof area with acceptable orientation.
4. See analysis of roof area availability for flat roof buildings on next page.
5. Assumes pitched roof accounts for 92% of total roof space, the balance 8% being flat roof space.
6. Note: The data are based on a study conducted by Navigant Consulting staff for a major U.S. utility company and adjusted for AZ specific based upon interview with Ed Kern of Irradiance, May 2006.

NAVIGANT CONSULTING

Not considering economics, the rooftop area available for *residential* PV could support ~7.5 GW of installations in 2025.

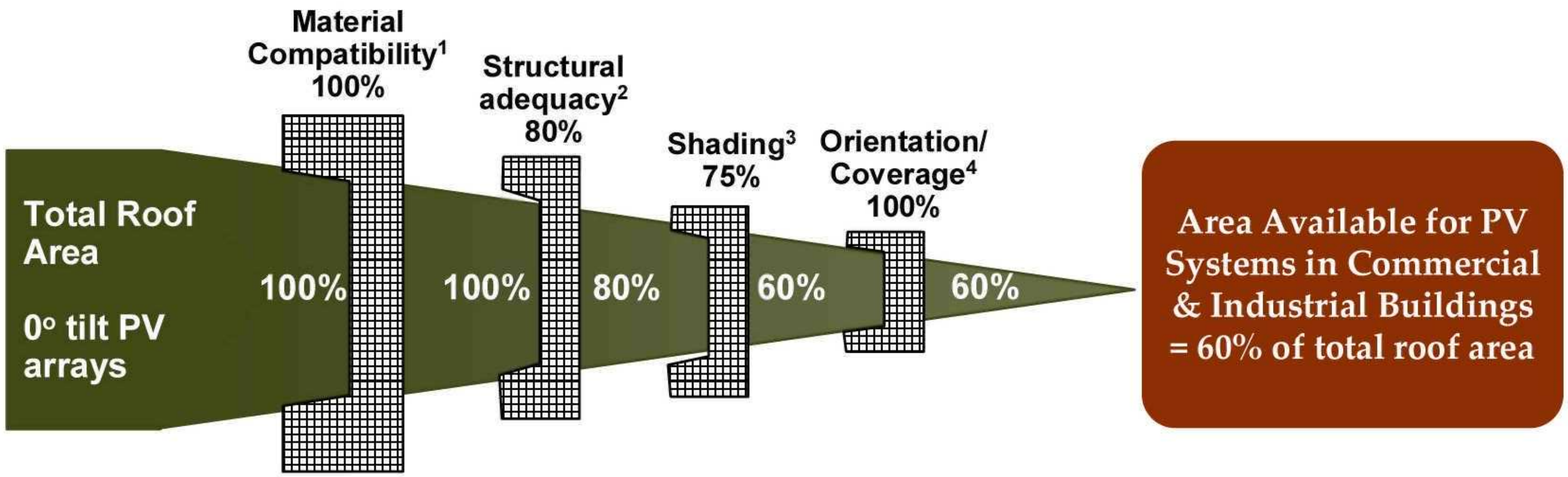
	Residential Roof Space and Solar PV Potential						
	Approx. Number of Homes[1,2]	Assumed Floor Space / Home (ft^2)[2]	Assumed Floors per Home[2]	Est. Total Roof Space (Million ft^2)[3]	Assumed % Available for PV[4]	Est. Roof Space for PV (Million ft^2)	Estimated Potential[5] (MWp)
2006	2,358,378[1]	1,433	1.65	2,048	27%	553	5,700
2010	2,540,643[1]	1,447	1.65	2,228	27%	602	6,210
2020	2,736,994[1]	1,484	1.65	2,461	27%	664	6,860
2025	2,948,520[1]	1,503	1.65	2,685	27%	725	7,480

Does not consider economics

1. Source: 2000 U.S. Census for number of homes and scaled with a 1.5% growth rate.
2. Source: U.S. Census Bureau, *American Housing Survey for the United States: 2003*, for homes in the Western United States
3. Calculated by multiplying column 1 times column 2 and dividing by column 3.
4. See assumptions on following pages.
5. Based on a 3kW system requiring approximately 300 ft^2 of space. This is based upon a module size of 5.25'X2.6' and a packing factor of 1.25 to account wiring, inverters, junction boxes, access to modules, etc.

NAVIGANT CONSULTING

The roof space available in *commercial* buildings for PV installations is around 60% of total roof area.



1. Roofing material is predominantly built up asphalt or EPDM, both of which are suitable for PV, and therefore there are no compatibility issues for flat roof buildings.
2. Structural adequacy is a function of roof structure (type of roof, decking and bar joists used, etc.) and building code requirements (wind loading, snow loading which increases the live load requirements). Since snow is not a design factor in most areas of Arizona, it is assumed at 20% of the roofs do not have the structural integrity for a PV installation.
3. An estimated 5% of commercial building roofing space is occupied by HVAC and other structures. Small obstructions create problems with mechanical array placement while large obstructions shade areas up to 5x that of the footprint. Hence, around 25% of roof area is considered to be unavailable due to shading. In some commercial buildings such as shopping center, rooftops tend to be geometrically more complex than in other buildings and the percentage of unavailable space may be slightly higher.
4. Flat arrays are assumed. If tilted arrays were assumed, then more space would be required per PV panel due to panel shading issues, which would reduce the roof space available.
5. Note: The data is based on a study conducted by Navigant Consulting for a major U.S. utility company adjusted for AZ specific based upon interview with Ed Kern of Irradiance, May 2006.

NAVIGANT CONSULTING

Not considering economics, the rooftop area available for commercial building PV could support ~7 GW of installations in 2025.

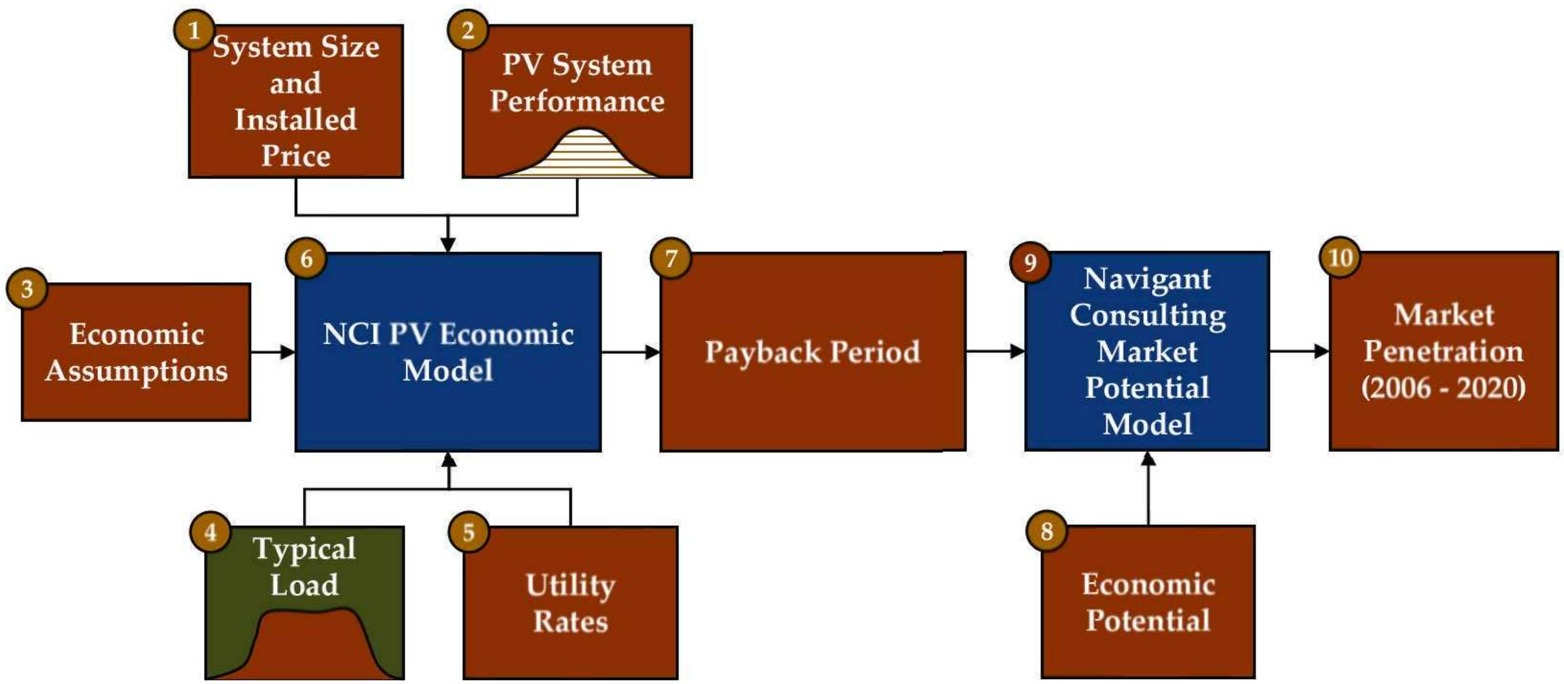
	Commercial Roof Space and Solar PV Potential					
	Approx. Floor Space (Million ft^2)	Assumed Average # of Floors	Estimated Total Roof Space (Million ft^2)[3]	Assumed % Available for PV[4]	Est. Roof Space for PV (Million ft^2)	Estimated Potential[5] (MWp)
2006	1,284[1]	1.5[1]	856	60%	514	5,303
2010[2]	1,363[2]	1.5	908	60%	545	5,629
2020[2]	1,582[2]	1.5	1054	60%	633	6,532
2025[2]	1,704[2]	1.5	1136	60%	682	7,037

Does not consider economics

1. Source: State of Arizona, Department of Commerce, Energy Office, May 2006 and scaled with a 1.5% growth rate.
2. Calculated by dividing column 1 by column 2
3. See assumptions on following pages.
4. Based on 250 kW system requiring 25,000 ft2 or ~100 sq. ft. per kW. This is based upon a module size of 5.25'X2.6' and a packing factor of 1.25 to account wiring, inverters, junction boxes, access to modules, etc.

NAVIGANT CONSULTING

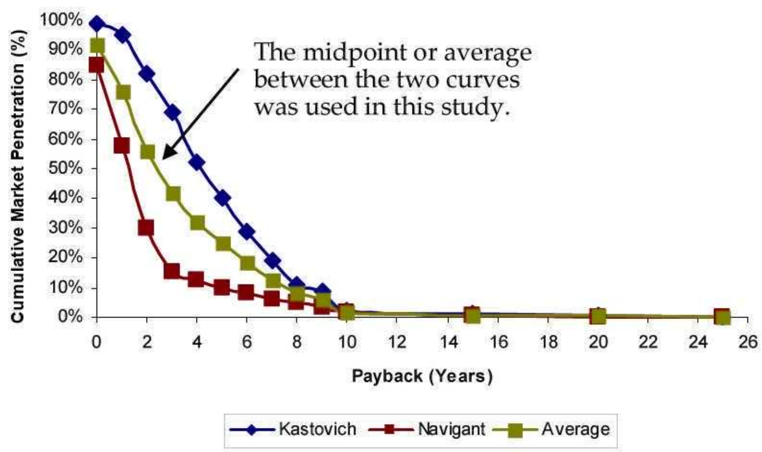
The approach used to assess the market penetration for customer-sited residential and commercial PV is illustrated below.



Note: For customer-sited PV, the analytical approach in step 9 in the flowsheet was used to estimate the market penetration, as described in the following pages.

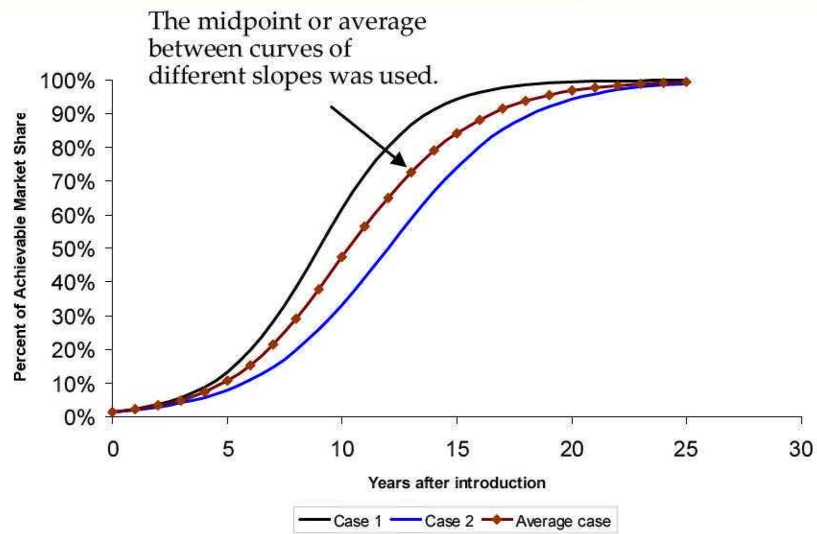
The market penetration potential is based on the payback period to the customer, and the rate of penetration is based on an S-Curve.

Payback vs. Cumulative Market Penetration Curves



- The curves provide the cumulative market penetration 10-20 years after product introduction, as a function of payback.
- The Kastovich curve is more aggressive than the Navigant curve: a midpoint between the two was thus considered in the analysis.

Typical S-Curve

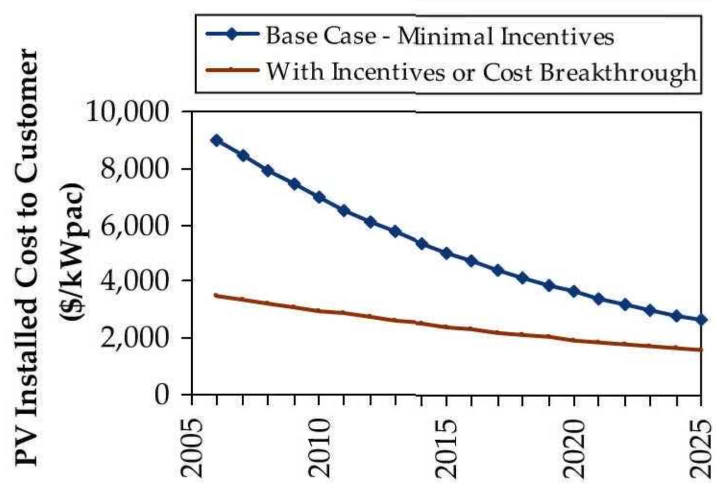


- The S-Curve provides the rate of adoption of technologies, which is a function of the technologies characteristics and market conditions.
- An average of two curves was used, given the many factors that will impact penetration of PV.

NAVIGANT CONSULTING

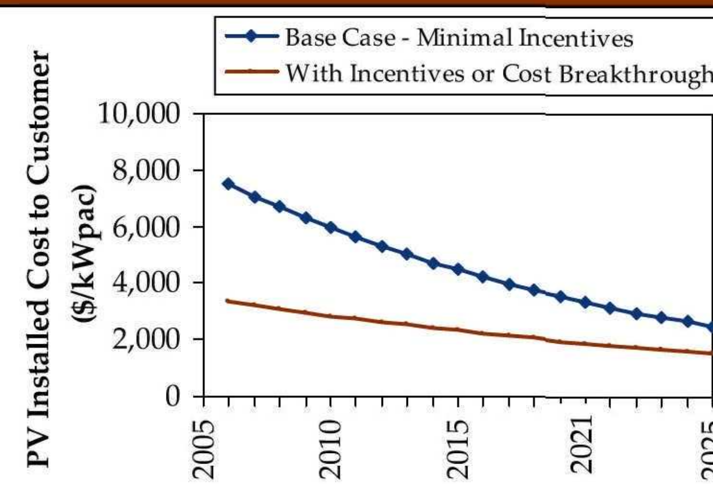
To estimate the market penetration of rooftop PV, NCI analyzed two scenarios for both residential and commercial applications.

PV Installed Costs - Residential



- Base Case assumes an average 6.2% decline in prices from 2006 at $9,000/kW to $2,650/kW in 2025. No incentives, except a $15/MWh REC which appreciates at 3% per year.
- With Incentive or Cost Breakthrough Case assumes the cost to customer declines an average 4% from $3,500/kW in 2006 to $1,600/kW in 2025. Prices could reflect a combination of incentives and/or cost breakthroughs.

PV Installed Costs - Commercial

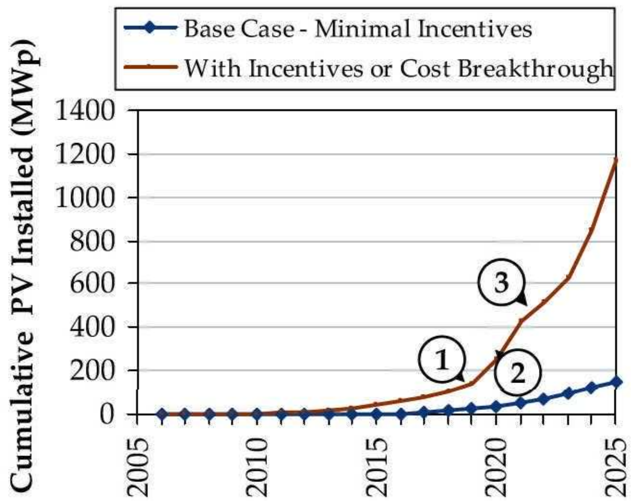


- Base Case assumes an average 5.6% decline in prices from 2006 at $7,500/kW to $2,500/kW in 2025. No incentives, except a $15/MWh REC which appreciates at 3% per year.
- With Incentive or Cost Breakthrough Case assumes the cost to customer declines an average 4% from $3,350/kW in 2006 to $1,550/kW in 2025. Prices could reflect a combination of incentives and/or cost breakthroughs.

Note: Installed Costs in the Base Case have been simplified for modeling purposes to reflect a constant annual percentage decline.

Cumulative installations of rooftop PV by 2025 is likely to be minimal unless significant subsidies or cost breakthroughs occur.

AZ Rooftop PV Market Penetration (Residential + Commercial)



- Significant market penetration does not begin until payback rates drop below 10 years. This occurs in 2020 in the incentive/breakthrough case
- Installed PV could increase more rapidly after 2025 if prices relative to the grid continue to drop

Source: Navigant Consulting, Inc. analysis, September 2006.

Key Market Dynamics

1. Installations cross a tipping point as the payback period drops below 10 years. However, not all customers adopt immediately. Current payback levels are 35 years for commercial and 32 years for residential, with incentives.
2. Installations accelerate as 1) the payback period decreases – causing more customers to want to buy PV systems, and 2) time passes and adoption increases (the slow adopters actually adopt).
3. Installations decelerate slightly as the slow adopters have already adopted, and new installations are driven primarily by those who have waited for the price to continue to come down.

NAVIGANT CONSULTING

Without incentives, market penetration in Arizona for rooftop PV in the near term is likely to be minimal.

	AZ PV Market Penetration – Residential Buildings – Base Case			
	2006	2010	2020	2025
PV Installed Cost ($/kW)[1]	$9,000	$7,000	$3,700	$2,650
Net Annual Savings ($/kW)	$166	$180	$218	$220
Payback	54	39	17	12
Cumulative Installed (MWp)[2]	0	0	29	96

	AZ PV Market Penetration – Commercial Buildings – Base Case			
	2006	2010	2020	2025
PV Installed Cost ($/kW)[1]	$7,500	$6,200	$3,300	$2,500
Net Annual Savings ($/kW)	$109	$124	$143	$166
Payback	69	50	23	15
Cumulative Installed (MWp)[2]	0	0	10	49

1. Installed Costs in the Base Case have been simplified for modeling purposes to reflect a constant annual percentage decline.
2. Economic analysis does not reflect the impact of early adopters.

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With incentives or further cost breakthroughs, payback periods in Arizona decline and start leading to greater purchases of rooftop PV.

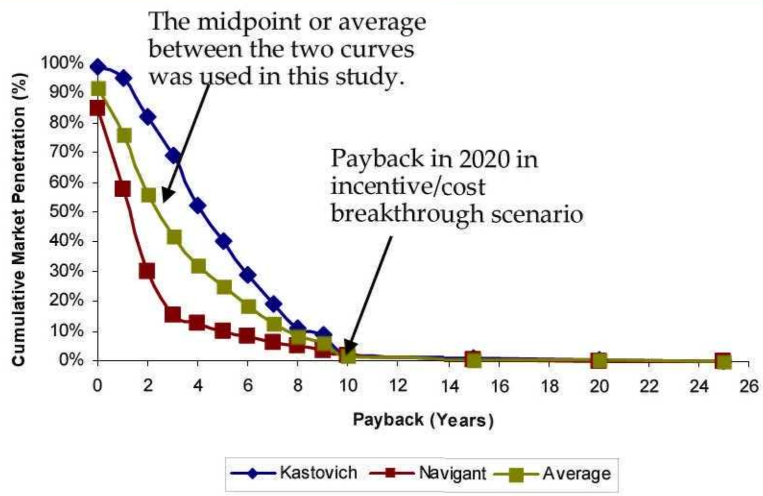
	PV Market Penetration – Residential Buildings – Incentive/Cost Breakthrough			
	2006	2010	2020	2025
PV Installed Cost ($/kW)[1]	$3,500	$2,970	$1,970	$1,600
Net Annual Savings ($/kW)	$166	$175	$205	$229
Payback	21	17	9.6	7
Cumulative Installed (MWp)[2]	0.3	3	187	829

	PV Market Penetration – Commercial Buildings – Incentive/Cost Breakthrough			
	2006	2010	2020	2025
PV Installed Cost ($/kW)[1]	$3,350	$2,845	$1,890	$1,550
Net Annual Savings ($/kW)	$108	$118	$1145	$165
Payback	31	24	13	9.4
Cumulative Installed (MWp)[2]	0	0.4	63	346

1. Installed Costs in the Base Case have been simplified for modeling purposes to reflect a constant annual percentage decline.
2. Economic analysis does not reflect the impact of early adopters.

Improvement to PV economics beyond the assumptions in the breakthrough scenario could significantly increase PV penetration.

Payback vs. Cumulative Market Penetration Curves



- The incentive/cost breakthrough assumes the payback to residential and commercial customers is near 10 years. Based on historical market penetration as described by the Kastovich and Navigant curves, any further improvement in PV economics would start having significant effects on market penetration.

Total Achievable Market Penetration in AZ

Payback (years)	Potential Cumulative Market Penetration (%)	AZ Technical Market Potential in 2025 (MW)	Total Achievable Market Penetration in AZ (MW)
15	~1%	14,520 MW (7,485 res, 7,035 comm)	145
12	~1.5%		215
10	~2%		290
9	6%		870
7.5	10%		1450
5	25%		3630

- The total achievable market penetration would be attained over several years as customers react to improved pricing – NCI uses an S-Curve to estimate this penetration.
- Analysis assumes the same payback and market penetration for residential and commercial markets.

NAVIGANT CONSULTING

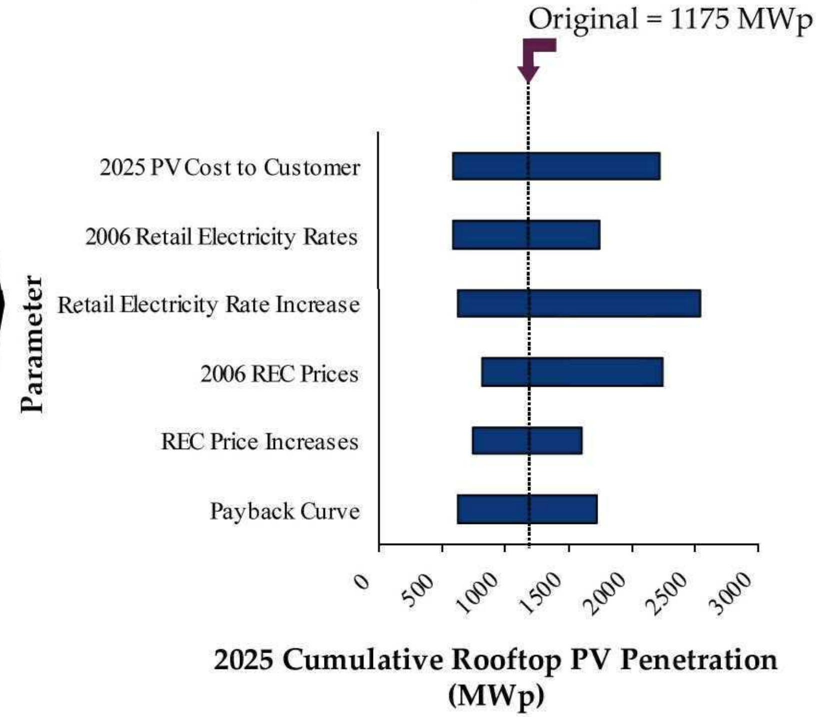
Electricity rate increases above the baseline assumption of 1% per year results in a significant increase in the market penetration of PV.

NCI PV Market Potential Model Settings and Sensitivity Range (With Incentives or Cost Breakthrough Scenario)

	Parameter	Baseline Setting	Range Tested
PV System Price / Performance	2025 Cost to Customer	\$1,600/Wp – Residential; \$1,550/Wp Commercial	+/- 20%
Electricity Prices and RECs	2006 Retail Electricity Rates	9.5 ¢/kWh Res, 7 ¢/kWh Comm	+/- 20%
	Electricity Rate Increase	1% per year	0% to 3%
	2006 REC Prices	\$15/MWh	\$10 - \$30/ MWh
	REC Price Increases	3% / year	0% - 5% / year
Payback Curve	Payback Curve	Average of Kastovich and NCI	Kastovich and NCI

Note: Only those parameters subject to sensitivity analysis are shown.

Market Penetration Sensitivity – With Incentives or Cost Breakthrough Scenario (Cumulative MWp in 2025, Residential and Commercial)



NAVIGANT CONSULTING

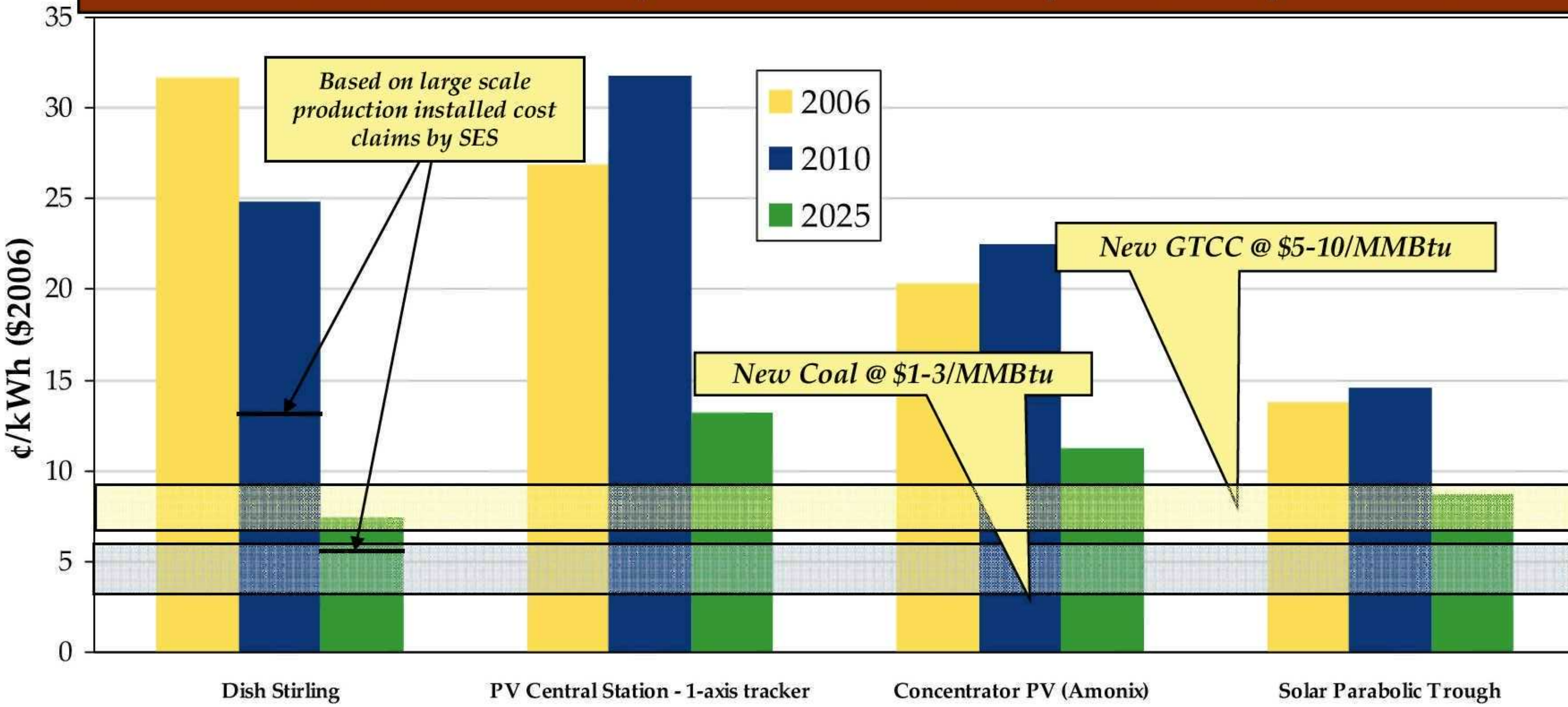
For the next 15 years, the principle opportunities for AZ central station solar include:

>> Meeting Arizona's peak load requirements
>> Fabricating hardware for stations to be built in the WECC

- Until about 2015, assuming forecasted gas prices, the demand for central solar will be driven by RPS and solar set asides.
- Under expected solar system cost reductions and gas price scenarios, central solar becomes economically competitive with gas-fired generation (especially, peaking) in the post 2015 timeframe.
- Arizona (especially when combined with Southern Nevada) is the fastest growing and a very large market for new capacity in the WECC
- Several other factors could increase the inherent value of solar relative to gas fired peaking capacity:
  - Gas prices are extremely volatile – this volatility should translate into an added benefit for solar.
    - Consumers buy insurance to protect against "worst case" scenarios
  - Solar is highly coincident with AZ utilities peak demand
  - If solar meets more of the peak demand, gas price volatility could be moderated
  - Greenhouse gas cost adders for fossil fuel may increase the cost of gas-fired generation by $5 to $10/MWh

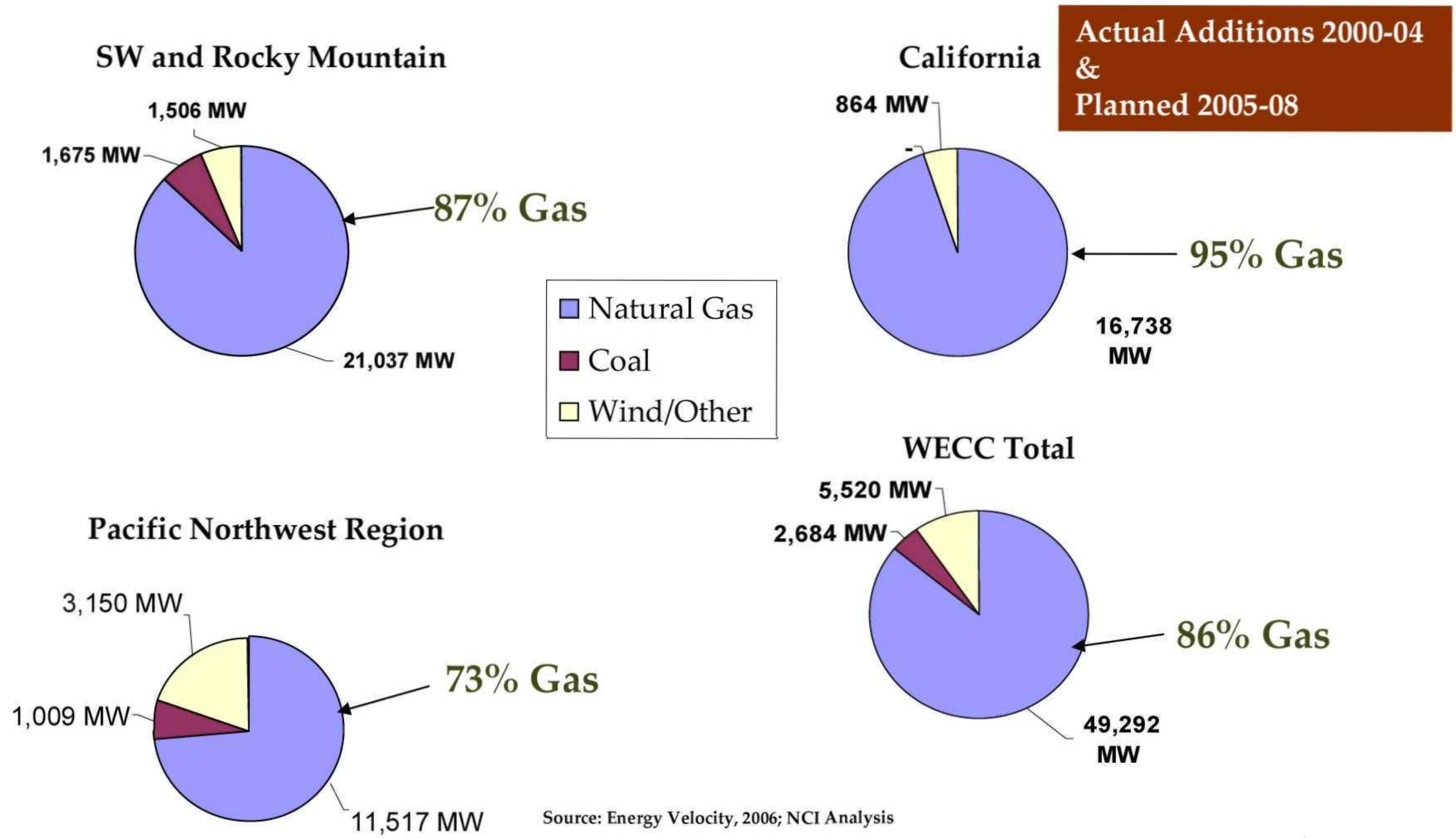
Technology improvements/cost reductions will allow central solar to compete with conventional baseload and intermediate generation.

AZ Levelized Cost of Electricity for Selected Wholesale Options (Developer Financed)*



Note: All cost estimates exclude additional revenue from renewable energy certificates. New Coal will generate electricity at 3.7 to 5.6 cents/kWh and new Gas Turbine Combined Cycle (GTCC) at 5.7 to 9.2 cents/kWh. *LCOE includes 10% ITC and accelerated depreciation, and 30% ITC for 2006. NCI analysis using data from NREL in 2006 and Bob Liden, Executive VP and General Manager, Stirling Energy Systems, for Dish Stirling, September 19, 2006.

Over 80% of new capacity in the WECC is gas-fired, with higher percentages in the desert Southwest and California.



Source: Energy Velocity, 2006; NCI Analysis

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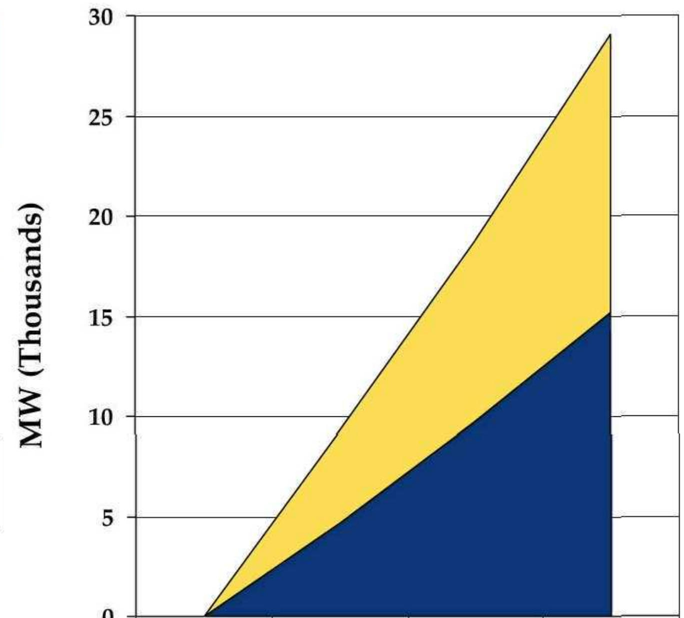
PUC-IR-304
DOCKET NO. 2008-0273
ATTACHMENT 2
PAGE 123 OF 189

Peak loads in the Desert SW states and California are forecasted to grow by nearly 2,000 MW per year for the next 15 years.

NERC Sub-Region	Expected Peak Load (MW) 2005-2020			
	2005	2010	2015	2020
AZ, NM, South NV	26,972	31,624	35,972	40,897
CA	57,324	61,985	67,031	72,492
Total	84,296	93,609	103,003	113,389

Peak Load Growth (MW)



	2005	2010	2015	2020
AZ, NM, & So NV	0	4,652	9,000	13,925
California	0	4,661	9,707	15,169

Source: WECC, CA Energy Commission, NCI Analysis

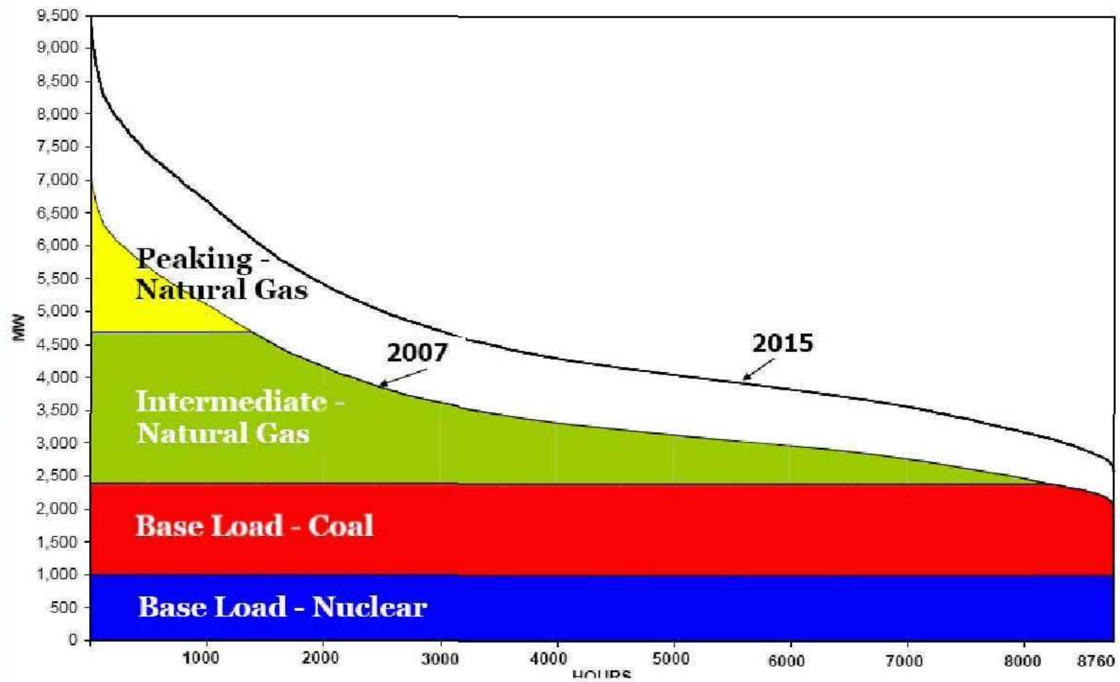
Peak growth in the Desert Southwest is forecasted to be nearly the same as California.

NAVIGANT CONSULTING

For APS, gas is the marginal fuel in almost all hours, with peakers being on the margin for as many as 1,200 hours.

- A critical issue is the coincidence of loads and solar output
- Electric load tends to peak later than the output from a solar plant
- A few hours of storage would allow one to match profiles
- Demand Response could be coupled with the solar programs to compensate for intermittency

APS 2007 & 2015 Load Duration Curves



Source:: APS 2006 Base Load RFP Bidder's Conference

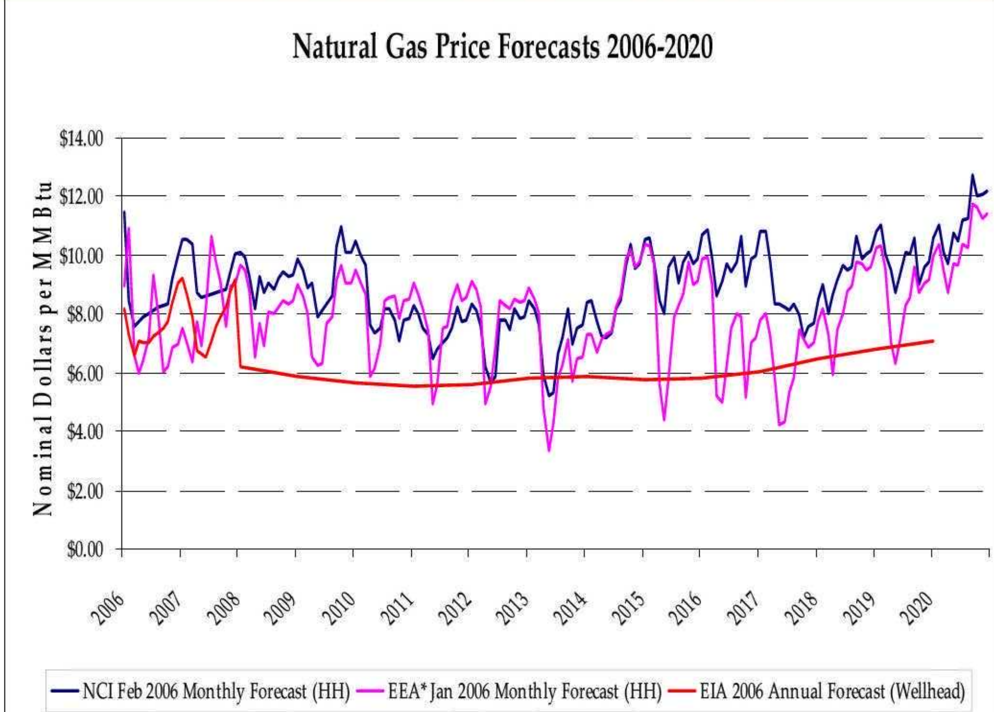
While APS has more gas than the rest of the state, gas is still on the margin for almost all daylight hours.

NAVIGANT CONSULTING

Gas prices may decline in the near future, but the long-term trend shows a return to higher prices.

- Many expect average gas prices to be higher than the EIA forecasts
- Seasonable and market conditions result in periods of sustained higher prices
- For this analysis, we recommend using an average price of $8.00/MMBTu for a reference forecast

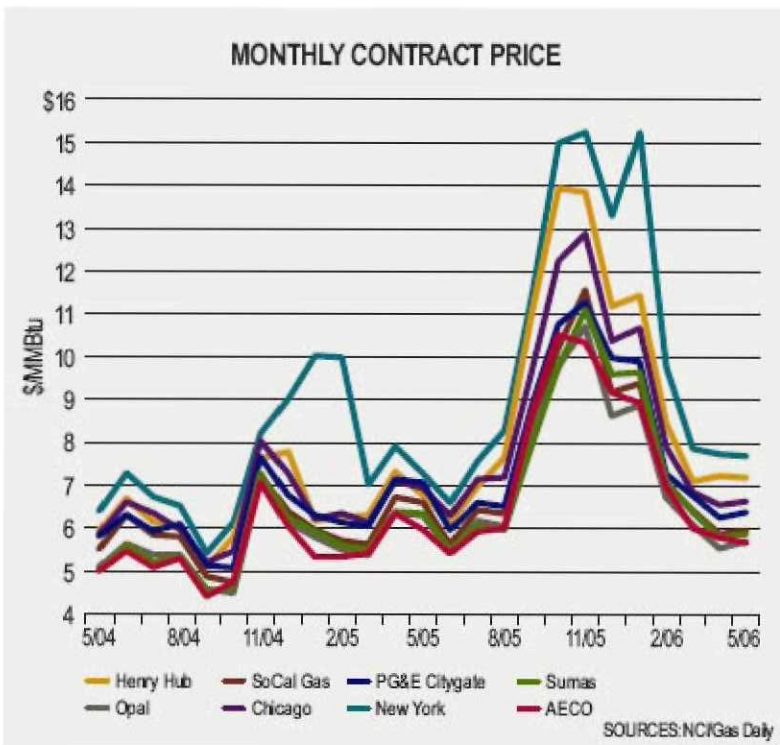
Sustained High Natural Gas Prices



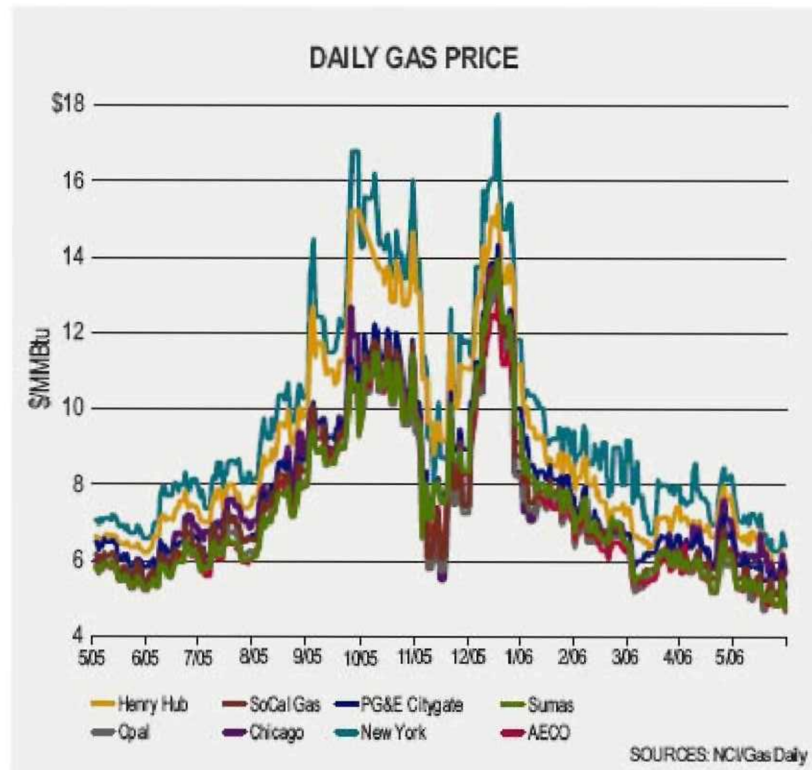
Source: EIA,2006; EEA, 2006, NCI Analysis

Gas prices are extremely volatile with prices being 50% to 100% above the annual average price for days or months at a time.

May monthly Index Price Was Off $0.15 per MMBtu to $5.67 per MMBtu, Continuing 8th Consequetive Month the Index Declined



April spot daily prices decline below $6.00 per MMBtu at Henry Hub; below $5.00 per MMBtu in Rockies, Canada and SoCal Border

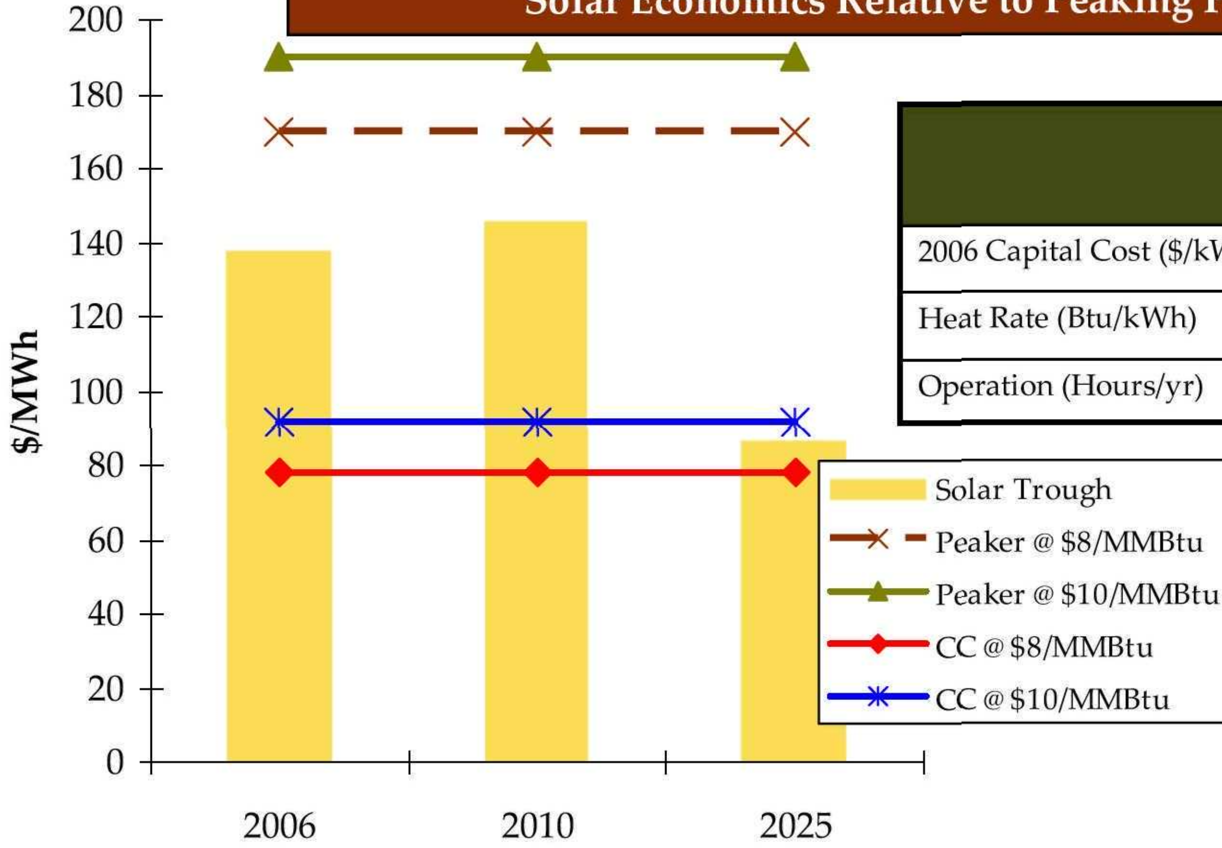


PUC-IR-304
DOCKET NO. 2008-0273
ATTACHMENT 2
PAGE 127 OF 189

NAVIGANT CONSULTING

The cost of electricity from parabolic trough is near the cost of peaking power today, and is expected to decline by more than 50% by 2025.

Solar Economics Relative to Peaking Power



	50 MW Peaking Plant	260 MW Combined Cycle
2006 Capital Cost ($/kW)	$500	$650
Heat Rate (Btu/kWh)	10,000	7,200
Operation (Hours/yr)	1,200	7,500

Note: LCOE for solar includes Federal Investment tax credit, and accelerated depreciation. 2010 and 2025 assumes 6 hours of storage.

NAVIGANT CONSULTING

The LCOE for electricity from solar is not directly comparable to the LCOE from peakers or combined cycle plants for a number of reasons.

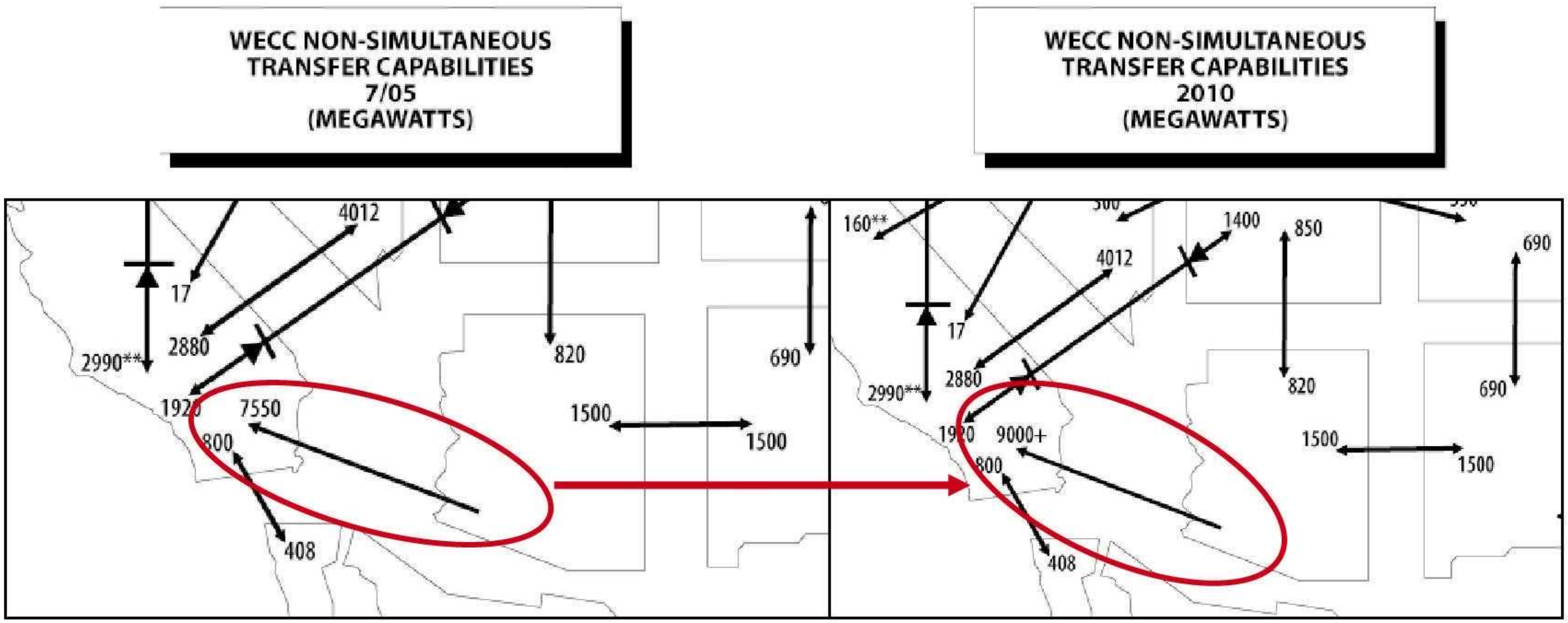
Discount Factors for Gas

- Peaker capacity may still be required to address:
  - Non-coincidence of system and solar peak
  - Intermittency
- Solar output is comparable to a mix of peaker and combined cycle
- Peaker capacity has added flexibility to generate when needed

Discount Factors for Solar

- Hedge value against gas price volatility
- Impact of lower gas usage upon average gas prices
- Value/compliance costs for emissions reduction
- Six hour storage capability built into post 2010 costs mitigate intermittency and non-coincidence issues

Electric transmission is a critical link. Under current infrastructure, potential exports to other markets are limited.



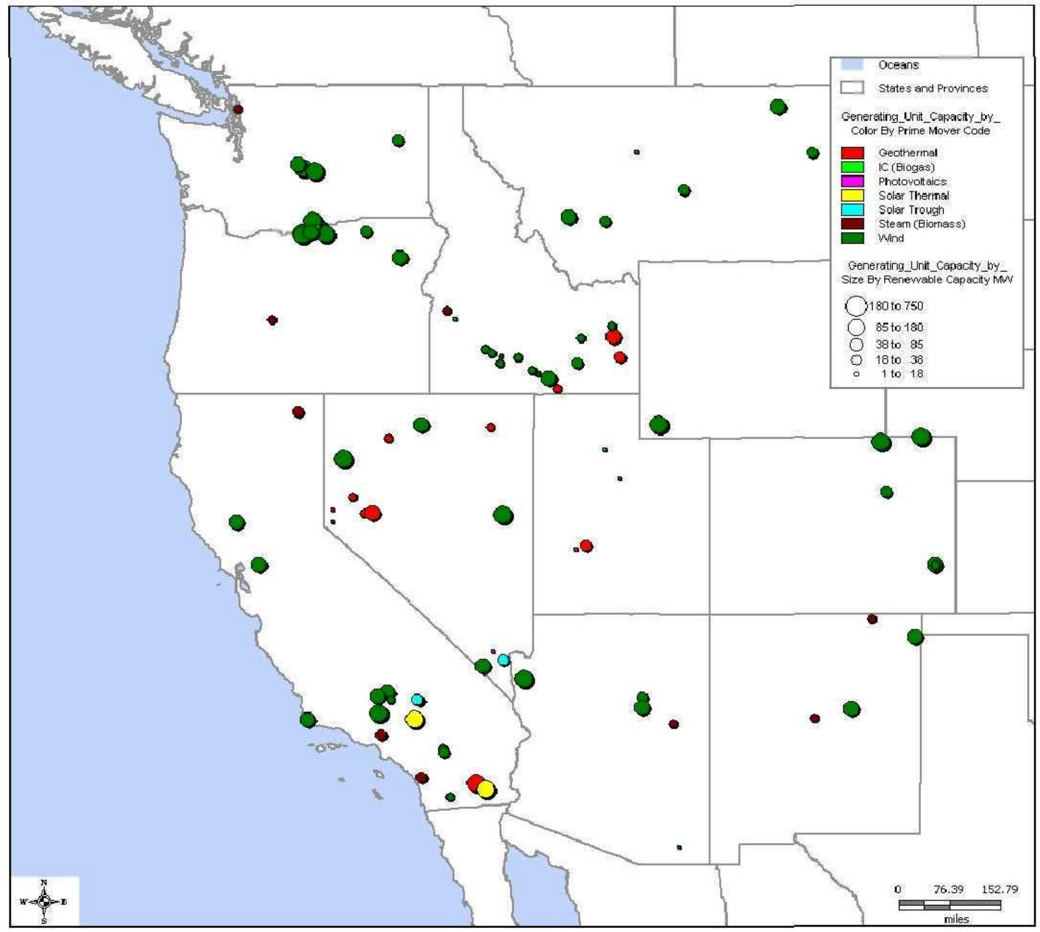
Source:: WECC, 2005

Planned upgrades may provide limited capability for additional exports.

There are currently an estimated 140 renewable energy projects being planned in the WECC.

Renewable Energy Capacity (MW) under development in the WECC:	
NW Power Pool:	**6,567**
Rocky Mountain:	**1,635**
AZ-NM- So. NV:	**1,001**
California:	**3,532**
Total:	**12,735**

- Wind accounts for most of the capacity additions
- There are a few major solar projects under development in Southern CA
- Some portion of these projects will not get developed
- AZ, NM, NV RPS needs are approximately 3,700 MW by 2020. CA adds another 14,100 MW.



Source: Energy Velocity, 2006; Navigant Consulting, Inc. analysis, 2006.

Two scenarios were developed for deployment of central station solar power through 2020.

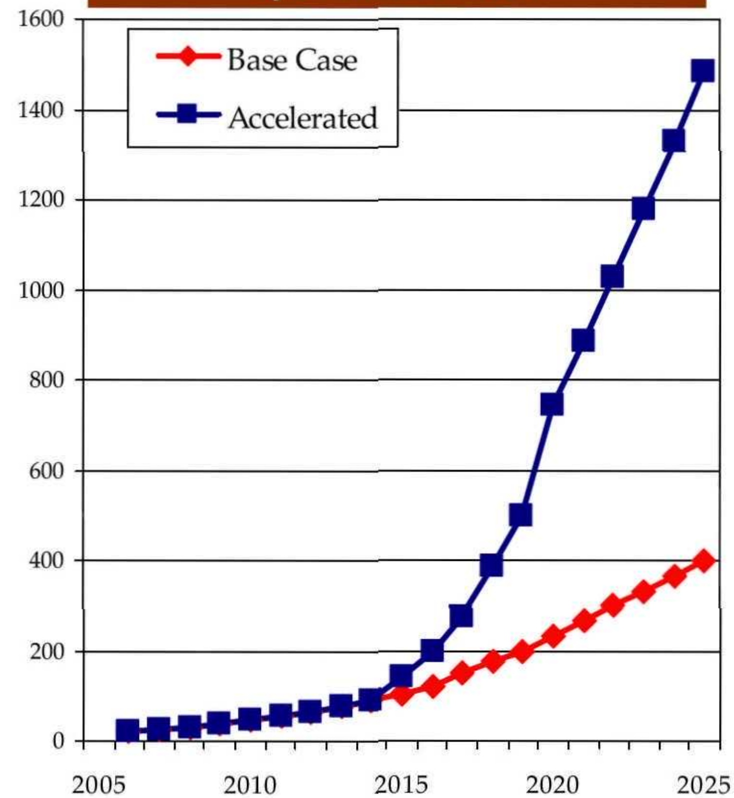
	Base Case	Accelerated
Key Assumptions	• Business as usual • Central solar costs decline, but no breakthrough • Average gas prices remain in the $7.00 to $8.00/MMBtu range • Siting and transmission issues result in minimal export capability • Solar trough has 6 hour storage after 2010	• Early central station solar technology projects perform as planned, and costs decline as forecast • Average gas prices in the $9.00 to $10.00/MMBtu range • Greenhouse gas and other emissions add $5/MWh to combined cycle costs • Transmission capability developed by 2020 to support an additional 200 MW of exports

NAVIGANT CONSULTING

In the breakthrough scenario, central station solar deployment expands dramatically after 2015.

- Through 2015, central solar captures about 10% of the RES requirements in both scenarios
- For the Base Case, central solar continues to capture about 10% of the RES applied on a state-wide basis (~ 400 MW by 2025)
- In the Accelerated scenario about 10% of 2015 capacity are central solar, ramping up to 20% of capacity additions by 2020. In addition, slightly more than 20 MW is developed for export annually

Central Station Solar Deployment by Scenario (MW)



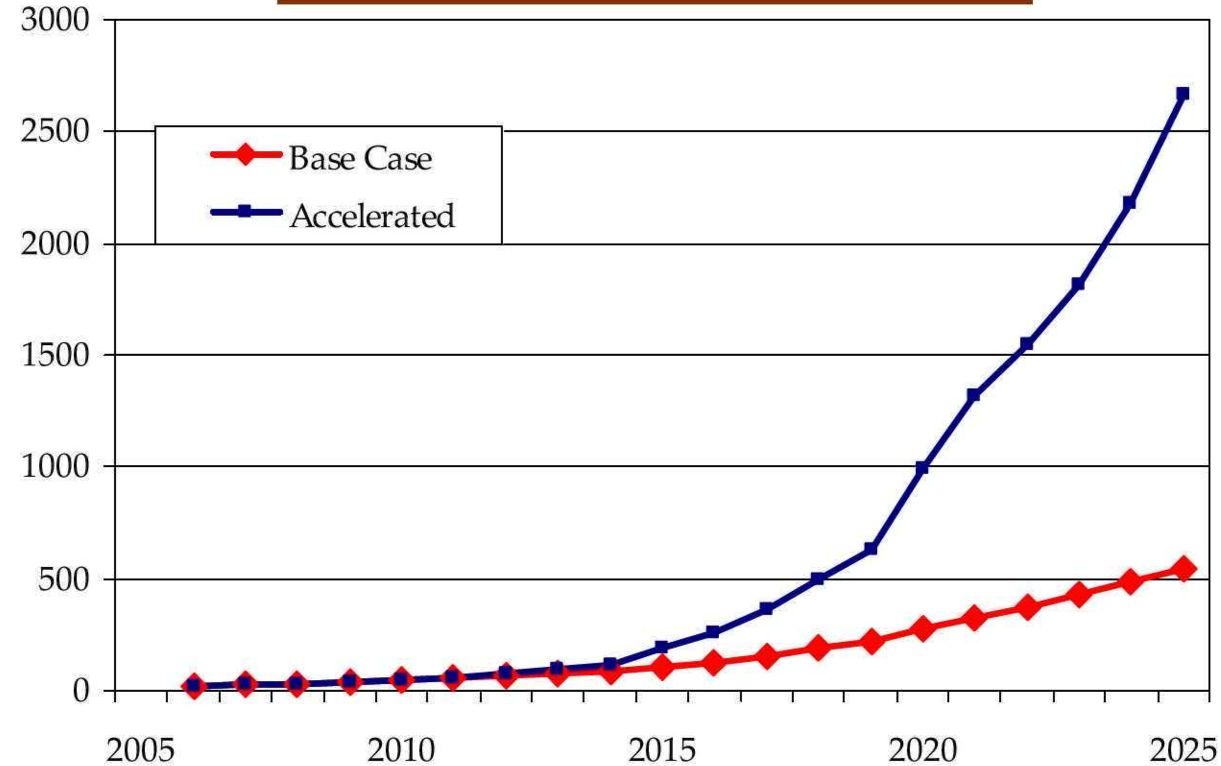
Source: Navigant Consulting, Inc. estimates, 2006.

The central station opportunities include both power production as well as manufacturing of components for plants to be built elsewhere.

Major Markets for Central Station Solar Development		
	2020 Market Size	**Considerations**
Power Production – AZ, NM, & So NV	120 to 130 MW/yr	Based on breakthrough scenario
Power Production for Export to CA	20-25 MW/yr	Limited potential due to CA favoring in-state renewables, and transmission
Manufacturing for Plants to be Built within Region and CA	100 MW/yr	Production costs lower in AZ than CA
Manufacturing for Export Out of Western U.S.		Production and shipping costs may limit exports

Total solar deployment could exceed 2,600 MW in the accelerated scenario with rooftop PV accounting for ~ 45% of the capacity.

Total Solar Electric Deployment (MW)



Job and direct earning PV impacts were estimated using NCI's proprietary models and industry interviews.

Primary Data Sources and Data Elements[1]	• NCI's PV module manufacturing cost model and LCOE (levelized cost-of-energy) model, provides detailed labor and non-labor cost estimates for all aspects of PV system manufacturing and installation • Interviews with PV industry sources – manufacturers, equipment suppliers, and installers • *The Work That Goes Into Renewable Energy*, Renewable Energy Policy Project (REPP), November 2001, Research Report No. 13
Method	• Use NCI models and interview results to confirm and update REPP labor estimates. Account for changes in technology, automation and material prices, and apply the updates to the range of available PV technologies • Weight the hours estimates by technology market shares to derive a weighted average hours for each labor task category • Convert weighted estimates to job-years (1 job-year = 1960 hours) • Using labor-hours and materials estimates per installation task from NCI's LCOE model, and labor rate data from interviews with industry professionals and R. S. Means, calculate labor costs for residential 3.5-kW, commercial 1,500-kW and utility central station 2-MW system installations. • Convert all results to per-MW costs

[1]In the manufacturing model, a process flow details each step and its costs, with technology improvements tracked as they occur. For each step, a detailed activity-based accounting is made of material, labor, capital and overhead costs, based on material quotes, machine capability spec sheets, machine cost quotations, U.S. labor rates, and industry financial parameters. The LCOE model accounts for module prices, inverter costs, installation labor, system integration, installer margins, etc. to build total system price, based on interviews with a wide array of industry sources.

Job and direct earnings impacts of central solar development were estimated for plant construction and O&M.

Primary Data Sources and Data Elements[1]	• April 2006 study of CSP development in California, including: — NREL Excelergy model data on components of capital and O&M costs for 100-MW parabolic trough plants constructed in 2007, 2009, 2011, and 2015 — NREL data on allocation of component costs to labor and non-labor — Authors' methodology for assigning certain labor costs to out-of-state resources • Interviews with NREL staff and authors of California CSP study
Method	• Review recent CSP economic development studies and determine most robust source[1]. • Estimate construction cost components for 2008, to match job estimate presented for a plant constructed in that year. • Estimate construction cost components for 2010 from 2009 and 2011 data. • Apply the NREL/CA study's percentage estimates (of cost component as a percentage of total cost, labor as percentage of each cost component, and in-state labor as percentage of each component's labor estimate) to the calculated 2010 component costs, to estimate in-state labor costs per component in 2010 and 2015. • Adjust component labor cost items, based on total capital cost estimates for 2010 and 2020 from interviews with NREL staff, using 2015 ratios of cost items for 2020. • Apply the same approach to develop O&M job and direct earnings estimates, using the NREL Excelergy model labor cost estimates. • Convert all results to per-MW values.

[1] *Economic Energy and Environmental Benefits of Concentrating Solar Power in California*, Black & Veatch, NREL/SR-550-39291, April 2006.

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Direct jobs[1] per MW of installed PV are projected to average 28 job-yrs for residential and 23 job-yrs for commercial/central station in 2010.

Year	Application	Direct Jobs Per MW of PV Capacity[1]			
		Wafer & Cell (Job -Yrs[2])	Module (Job-Yrs)	Installation (Job-Years)	Annual O&M
2010	Residential	8	3	17	0.2
	Commercial	8	3	12	0.4
	Utility	8	3	12	0.4
2020	Residential	2	1	11	0.2
	Commercial	2	1	9	0.4
	Utility	2	1	9	0.4

[1] "Direct jobs" does not include economic multiplier effects of spending in the local economy.
[2] One job-year is equal to 1960 hours (40 hours per week, 49 weeks per year)
Source: Navigant Consulting, Inc. estimates, June 2006.

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Each MW of central solar plant capacity should generate 4.3 job-years in 2010. The direct job impacts are expected to decline 30% by 2020.

Year of Construction	Direct Jobs[1] Per MW of Central Solar Capacity	
	Construction (Job-Years[2])	Annual O&M
2010	4.30	0.4
2020	2.99	0.3

[1] "Direct jobs" does not include economic multiplier effects of spending in the local economy.
[2] One job-year is equal to 1960 hours (40 hours per week, 49 weeks per year)

Source: Navigant Consulting, Inc. estimates, June 2006.

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PV manufacturing/assembly labor expenditures are expected to decline severely (70-80%) from 2010 to 2020…

Year	Application	Direct Labor Expenditures Per MW of PV Capacity			
		Wafer & Cell	Module	Installation	Annual O&M
2010	Residential	$600,000	$90,000	$2,500,000	$11,000
	Commercial	$510,000	$74,000	$1,500,000	$22,000
	Utility	$540,000	$79,000	$1,300,000	$22,000
2020	Residential	$130,000	$19,000	$1,700,000	$9,000
	Commercial	$150,000	$22,000	$1,000,000	$19,000
	Utility	$150,000	$22,000	$950,000	$19,000

Source: Navigant Consulting, Inc. estimates, June 2006.

… while installation labor should decline only by 25-35% -- better prices, fewer jobs.

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Central station power labor expenditures are much lower, on a per-MW basis, than those of PV, but annual O&M labor expenditures are higher.

Year of Construction	Direct Labor Expenditures Per Central Solar MW Capacity	
	Construction	Annual O&M
2010	$550,000	$40,000
2020	$380,000	$35,000

Source: Navigant Consulting, Inc. estimates, June 2006.

Declines in CSP construction labor 2010-2020 should be like those of PV installation, with smaller declines in O&M labor.

The accelerated scenario for solar could add over 3,000 jobs in 2020.

Accelerated Scenario	Cumulative Capacity (MW)	Installations in 2020 (MW/yr)	Direct Manufact. (# Jobs*)	Installation/ Construction (# Jobs)	O&M (# Jobs)	Installation Labor Expenditure (Million $)	O&M Labor Expenditure (Million $)
Rooftop PV	250	115	450	1,800	75	243	4
Central Solar	742	143	60	429	233	54	26
TOTAL	992	258	510	2,229	308	297	30

*Assumes none of central solar components are manufactured in AZ, except for PV where 20 MW were assumed to be manufactured in state. Assumes that an additional 150 MW plant is in AZ for the rooftop PV market (some in state and some exported).

Source: Navigant Consulting, Inc. estimates, June 2006.

Total 2020 employment = 3,047 jobs for solar in an accelerated scenario

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Emission reduction is estimated at 400,000 tons per year in an accelerated scenario in 2020.

Emission Reduction Potential in AZ (Accelerated Scenario in 2020)				
Accelerated Scenario	Cumulative Capacity (MW)	Average Capacity Factor (%)	Energy Delivered (MWh)	Total CO_2 Reduction (Tons)
Rooftop PV	**250**		**388,075**	**60,000**
• Residential	187	18.3%	299,775	
• Commercial	63	16%	88,300	
Central Solar**	**742**		**2,182,500**	**338,200**
• Trough	519	38%	1,728,000	267,800
• Dish Stirling	148	23%	299,000	46,300
• PV	37	25%	81,000	12,600
• Concentrating PV	37	23%	74,500	11,500
TOTAL	992	26.3%	2,570,575	**398,200**

*Assumes .31 lbs/kWh of CO2 are displaced for a Combined Cycle Gas Turbine in 2020.
** Assuming market shares of: 70% trough, 20% dish Stirling, 5% concentrating PV, and 5% flat plate PV based on economics.

Source: Navigant Consulting, Inc. estimates, August 2006.

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Table of Contents

Manufacturers indicated that new collaborative business models that provide a win-win for all involved could help to attract companies.

Manufacturer Interviews	
Conditions for relocating/initiating manufacturing in AZ	• Different collaborative business models with community activities vs. just single one-off rooftop installations. May not lead to more manufacturing jobs, but will create more jobs. • Incentives that are aligned with manufacturing production volumes of 500 MW – 1 GW plants (what will be built in the next 3 – 4 years (a $250 million to $1 billion investment
Main barriers to developing a vibrant AZ solar industry	• Limited supply of modules • Stronger market opportunities elsewhere and often consider expanding close to good markets
Ways of overcoming barriers	• Sustainable market growth will justify manufacturing
Two most important things that AZ could do to promote solar	• Increase the potential for scale with new collaborative business models • Require that a certain percentage of new homes in a development must be solar
Activities of other states or countries	• Income tax holiday (corporate and personal); Free real estate; Power at reduced rates; Access to water • Germany: up to 35% benefit up front vs. tax credit. Capped at $500,000 per year
Export potential	• Japan, Germany, Spain, Italy, Czech Republic, South Korea, India, China, NJ, CA

Source: Interviews with BP, Sharp, and a large semi-conductor company, May and June 2006

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The ACC expressed a desire to invest RES dollars in R&D, but was concerned about solar intermittency, cost, and siting issues.

ACC Interviews

Main barriers to developing a vibrant AZ solar industry

- Cost. AZ's strongest renewable resource is solar and it is four times more expensive than alternatives. Utilities need to look at lowest cost resources. RPS helps as long as AZ-sourced/delivered power is required.
- Intermittency of solar, therefore need spinning reserves supplied by natural gas technology
- Siting: It will be difficult to site 5 acres per MW. They have issues siting a 10 acre substation.
  - large % of available land is Trust Land that yields high prices (maximizing revenues for education). Perhaps the state could work to make certain land (e.g., land around prisons) available at lower cost. Siting problems likely to stem from local opposition, not opposition from the state. High prices of auctioned land trusts.
- Lack of infrastructure to install and service solar
- Technology is too immature to justify making large scale investments at this time
- High price of gas may limit hybrid solar/combined cycle projects.
- Lack of infrastructure – need to build up installation/servicing capabilities. Educational efforts and long-term commitment needed.
- For CSP – lack of long-term contracts so that developers can obtain financing. New RPS provides more of an incentive for utilities and developers to enter into long-term contracts.
- Transmission capacity – limited availability, public (NIMBY) & armed forces (training obstacle) opposition, competition from other states for capacity that is built.
- Negative historical experience with solar water heaters and freezing. Educational efforts and training will be needed.

Source: Interviews with Chairman Hatch-Miller, Kris Mayes, and Ray Williamson, June 2006.

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The state might consider discounting state land for solar development.

ACC Interviews (continued)	
Role of Utilities in Developing Solar Power	• Due to utility regulation, utilities are prime movers for energy policy. • New 30% distributed resource requirement will require utilities to aggressively involve customers, which will require significant educational and promotional efforts.
Ways of overcoming barriers	• Need to provide low cost and reliable power • Convert heat into cooling • Governor to have state agencies discount land of state facilities (e.g. land around prisons)
Ideas for RES funds	• Provide funds to universities for solar research. This would be an investment. • Provide grants to the private sector
Export potential	• Transmission capacity is an issue for export of solar power to other states — Frontier and TransWest transmission projects are far off — Transmission lines and towers interfere with training for the armed forces in AZ — No desire to turn Arizona into an "energy farm" for other states
Renewables Surcharge	• RPS % ramp-up designed to match ramp-up in load growth. Higher ramp rate not likely to be an easy sell.

Source: Interviews with Chairman Hatch-Miller, Kris Mayes, and Ray Williamson, June 2006.

Tribes could offer land for CSP generation/PV manufacturing plants, but seek local jobs and revenue-sharing in return.

Tribe Interviews	
Conditions for locating solar manufacturing or power generation on Tribal Lands	• Everything varies by tribe, but generally a favorable disposition to renewables. • Land is probably available for siting manufacturing or solar generation, but tribes will want a partnership rather than leasing of land.
Main barriers to developing solar electric facilities on tribal lands	• Manufacturing plants/solar generation: — Generally, low skill level of locals, and objections to bringing in workers from outside tribal lands to take jobs — Resistance to straight leasing deals; prefer partnerships — Concerns about utility cooperation with transmission/distribution pricing • PV installation: — Lack of home mortgage financing and housing shortage leads Housing Authorities to choose more, less expensive houses over fewer, higher-quality houses (small pay-off seen from enormous PV cost increment) — Lack of net metering; concerns about lack of utility cooperation
Ways of overcoming barriers	• Significant training, and commitment to long-term training and retention of tribal workers might address significant employment issues and provide local labor • Opportunities for revenue-sharing, empowerment zoning, tax credits, other partnerships
Three most important things that AZ could do to promote solar	• Make it easier to IPPs to enter market. Ensure general cooperation by utilities • Tax rules and access to portion of tax revenues • Help educate tribes on business and politics of energy

Source: Interview with Inter-Tribal Council representative – Dave Castillo.

A leading builder in the state suggested providing a lower electric rate for customers who use solar and providing more solar education.

	Builder Interview
Main barriers to developing a vibrant AZ solar industry	• Solar is the highest cost renewable • Lack of customer demand and awareness – There is virtually no demand for solar among prospective homeowners. Salespeople report that customers view solar as new, "techy", and experimental. • Other states have more diverse set of renewable resources (wind and biomass) • Past experience and association with solar hot water will need to be overcome • Market forces – Currently, the home-building market is in a slow-down, with the market flooded with used homes. Sales of new homes have dropped by 50%. • Pulte builds 6,000 homes per year and there is limited demand for solar — Customers view solar as new, high-tech, cutting-edge, experimental
Possible solutions	• Provide a lower electric rate or similar incentive for customers who use solar • Present solar as a hedge against rising electric rates • Educate customers on current status of solar technology and on solar benefits (including non-economic ones) • Once there is initial demand, educate developers, who can then conduct research with customers regarding adding solar to homes.

Source: Interviews with Pulte Homes, June 2006.

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The Executive Director of the Solar Energy Research and Education Foundation identified several areas for overcoming PV barriers.

Barriers

- Solar has no leverage with home builders
- Home owner association governance can prevent solar development
- The first cost of solar is often too high

Possible Solutions to Overcome Barriers

- Facilitate expedited permitting for new homes with solar
- Build public awareness to help home owners realize the value of solar and for consumers to understand that they are reliable and proven systems
- Provide zero interest financing or bonds to utilities that offer solar to customers
- Create a market for solar and the jobs will come
- Develop a long term (5 – 10 year) strategy that is reliable and consistent

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The interviews identified several ideas for overcoming solar barriers and to increase employment in the state.

"Make incentives simple and stable, and link incentives to performance. Our state has focused on installation as well as manufacturing. All systems over the past three years have been inspected for quality and performance…and we get back to contractors about what worked and what did not. Two years ago we started a 35% Business Energy Tax Credit for energy efficiency and renewable energy that is applied to the total capital cost. It is spread over 5 years and applies to up to $10 million per project."	Chris Dymond, Senior Energy Analyst, Oregon Department of Energy
"Have state agencies work together to support solar growth by providing or discounting the land of state facilities, e.g. land around state prisons, so that developers face lower land acquisition costs."	Ray Williamson, ACC
"Ways to overcome barriers include: facilitate expedited permitting for new solar homes, build public awareness about the reliable performance, provide zero interest financing or bonds to utilities offering solar. Be certain to develop a long term strategy that is reliable and consistent. Create a market and the jobs will come.".	Peter Lowenthal, Executive Dir. Solar Energy Research & Educ. Foundation
"Other countries are offering an income tax holiday (corporate or personal, free real estate, power at reduced rates, and access to water…we are however, interested in identifying different collaborative business models."	Lee Edwards, CEO, BP Solar
"Perhaps the greatest lesson learned from the past few years is to place a high premium on patience (sustainable results do not appear overnight) and flexibility (programs need to evolve with the market)."	Jeff Peterson, Program Mgr for Renewables, NYSERDA

Table of Contents

NCI's road-mapping process identified actions/recommendations based on analyses of the market opportunities, competition, and barriers.

Market Opportunity	Potential Benefits To Arizona	Arizona Competitive Position	Barriers	Roadmap & Action Plan
• Research & Development • Manufacturing • Distributed systems deployment • Central station development & operation	• Jobs • Supply security • Electricity prices and stability • Reduced emissions • Image	• Strengths • Weaknesses • Threats • Areas of competitive advantages	• Financial • Institutional • Infrastructure • Availability • Wholesale markets • Transmission • Siting • Other	Policy and program recommendations and action items for: • Near–term • Mid-term • Long-term

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There are many unique attributes in AZ that were identified in the interviews that were incorporated into the roadmap.

AZ Uniqueness & Strengths

- AZ Corporation Commission proactive leadership on its Renewable Energy Portfolio Standard
- AZ population and economic growth
- The excellent solar resource (high direct and diffuse solar radiation which is excellent for concentrating and flat plate PV)
- AZ high dependence on gas and its volatile price
- The ideal and central location of AZ to key nearby solar markets (TX, CA, NV, CO, NM)
- State Trust Lands and tribal lands could be used for large scale solar developments
- Competitive labor costs and tax rates
- ASU Poly PV certification capability is only one of three in the world (other 2 are in Northern Italy and Germany)
- ASU hosts the Power Systems Engineering Research Center, a consortium of 13 universities and 39 companies which is funded by the National Science Foundation
- Availability of funds close to $1.2 billion from RES through 2025 ($60 million per year)
- ASU assets (e.g. clean room, monitoring and evaluation equipment)
- UA assets (R&D on 3rd generation solar cells, clean rooms and characterization equipment)
- STAR facility for evaluating emerging technologies (only 2 others in world: Weizmann Institute in Israel and Australian National University)

Many threats were also identified through the interviews.

- A natural gas price collapse would reduce the competitiveness of solar
- Public concerns about NIMBY, aesthetics etc., may influence and limit the siting and large-scale deployment of central plants
- The planned use of central station or next generation PV systems that have not been fully proven may weaken the initiative
- Sustained economic recession results in concerns about investments in initially more expensive solar options
- Module shortage persists so systems can not be obtained to be installed

Key Threats

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Several barriers were identified for large scale development of customer sited and central station solar.

- Capital cost
- Technology immaturity
- Significant solar incentives in other countries
  - Tax holidays (personal and corporate); free land; reduced power rates; access to water; and plant cost subsidies of 30 – 45% in locations such as Germany
- Lack of PV educated human capital and infrastructure
- Low utility rates relative to other nearby states
- Lack of local strong market (relative to other some other U.S. states)
- Competition from neighboring states (e.g. NM manufacturing incentives)
- Perception of the need for gas back-up with solar to address intermittency
- Local building codes
- Homeowner associations and restrictions on solar installations

Key Barriers

NCI identified initiatives to help eliminate rooftop PV solar barriers.

	Rooftop PV		
Barriers	**AZ Solar Marketing and Outreach**	**Solar Zone**	**AZ Sustainable Partners**
High Capital Costs	○	●	○
Availability of Modules	○	○	○
Solar Incentives in Other States	●	●	⊙
Lack of Infrastructure	○	⊙	○
Public Perception	●	●	●
Low Utility Rates	○	○	○
Lack of Strong Local Market	⊙	●	●
Local Building Codes	○	●	○
Homeowner Association Restrictions	⊙	●	○

Key to Effectiveness: High ● Medium ⊙ Low ○

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NCI identified initiatives that could help to overcome key central solar initiatives.

Central Solar		
Barriers	AZ Solar Marketing and Trade Mission	Central Station Solicitation
High Capital Costs	○	●
Availability of Modules	⊙	○
Solar Incentives in Other States	●	●
Technology Immaturity/Risk	⊙	⊙
Siting/Land Use	○	○
Utility Ownership Issues	○	●
Intermittency/ Coincidence	○	⊙

Key to Effectiveness: High ● Medium ⊙ Low ○

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NCI identified initiatives to overcome possible R&D barriers.

R&D	
Barriers	**Center of Excellence**
High Capital Costs	⊙
Competition in Other States and Countries	●
Public Perception	●
Insufficient Intellectual Capital	●

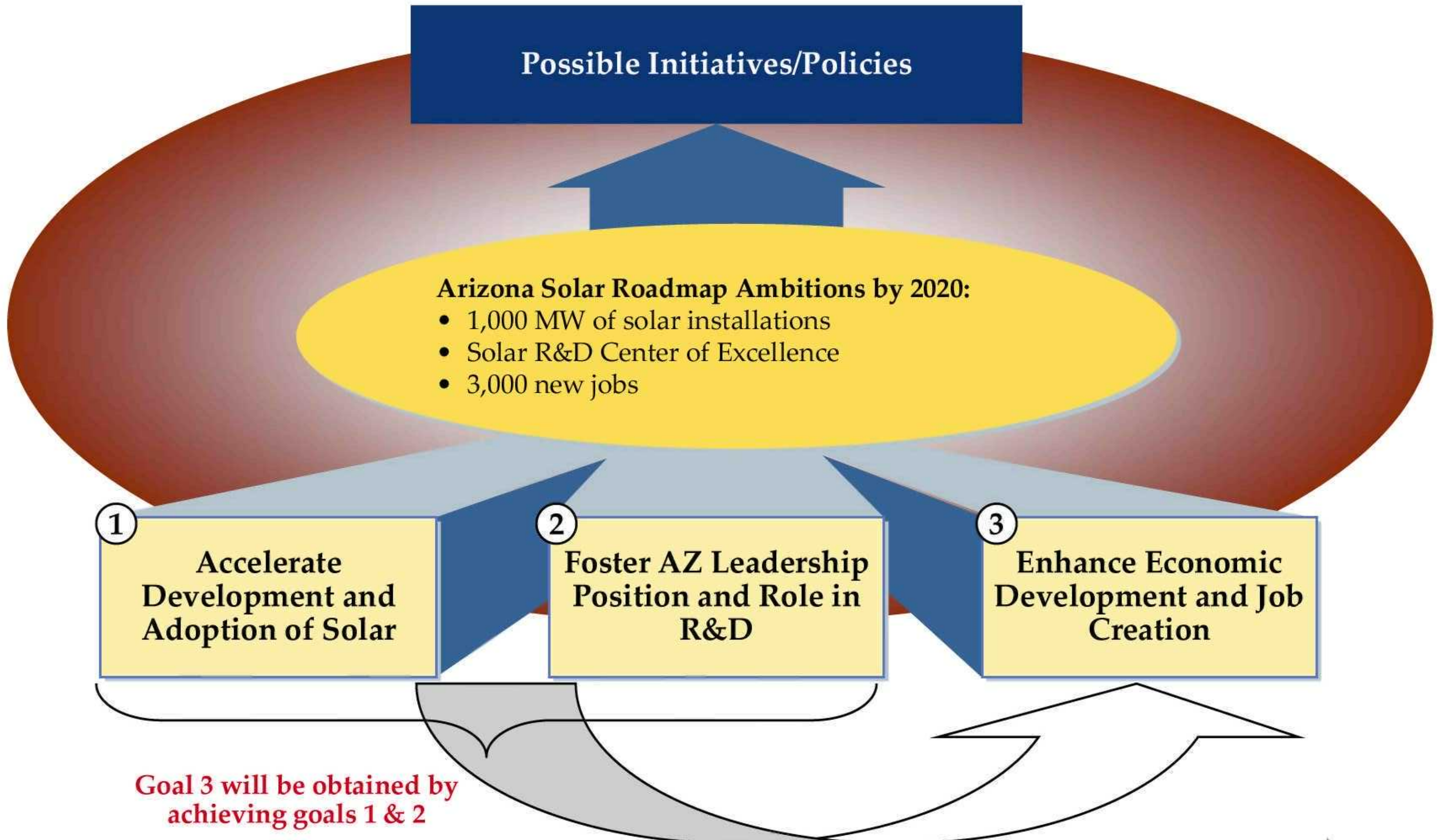
Key to Effectiveness: High ● Medium ⊙ Low ○

If some of the barriers can be overcome, there is potential for annual installations > 250 MW/yr in 2020, resulting in close to 3,000 new jobs.

Opportunities

- MWs in 2020 (Accelerated Scenario):
  - Central Solar: 145 per year
  - Rooftop: 115 per year
- Jobs in 2020 (Accelerated Scenario):
  - Direct Manufacturing: 510 per year
  - Installation/Construction + O&M: ~2,535
- Emissions Reductions in 2020 (Accelerated Scenario):
  - Central Solar: ~338,200 Tons of CO_2/Year
  - Rooftop: ~60,000 Tons of CO_2/Year
- Spin-off value of R&D development
- Additional economic development e.g. tourism to visit solar "centers of excellence" and deployment centers
- Enhanced sustainable AZ: maintaining AZ's quality of life

NCI along with the Steering Committee identified initiatives and policies that would address three goals and ambitions.



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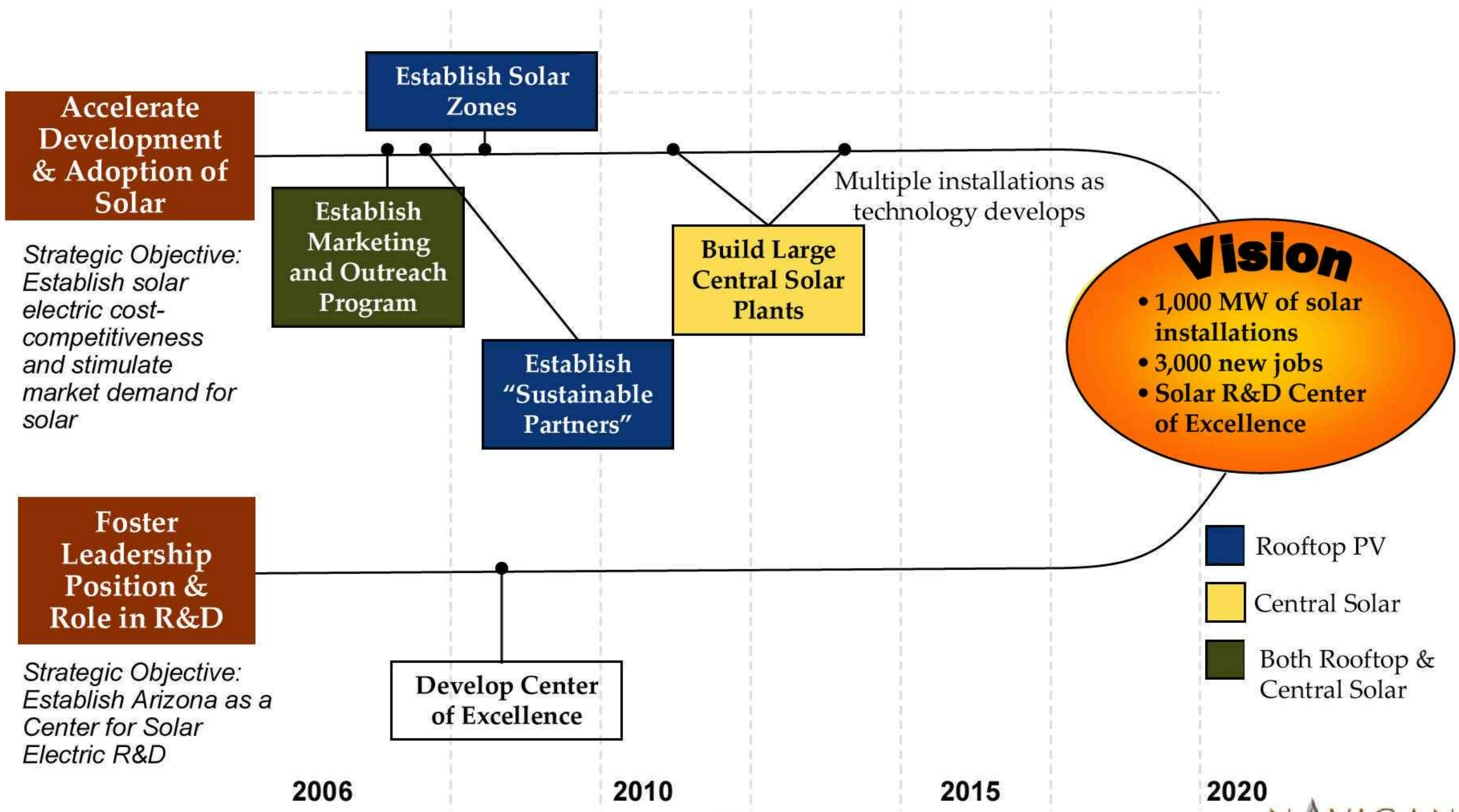
The vision and ambitions are achieved through integrated initiatives that build upon established policies and incentives.



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Establish Master Planned Community Alliance that provides scalability, reduces costs, and raises the value of distributed solar energy systems.

Solar Zones for Large Solar Development Action Plan	
Action/ Rationale	*Deliver a fully integrated 30-50 MW distributed solar project that targets the scale, cost, performance,* reliability and aesthetic requirements of large master planned communities. Establishes AZ as a market leader-- first with solar distributed energy applications large enough to impact grid infrastructure. support. Uses market forces and R&D dollars to stimulate innovation. High profile exposure.
Barriers Addressed	Developers, builders, homeowners require technical and financial risk reduction strategies and viable roofing to community designs and system siting options. Utilities need to allay power quality, reliability and safety concerns, understand interconnection architectures needed to support 30 MWs or greater of concentrated distributed generation. Municipal planners need greater understanding of benefits of distributed solar energy systems. Industry needs large single market to achieve learning cost reductions. Buying public needs a real demonstration community.
Potential Risks	Community wide system proves technically unworkable or financially not viable Unable to attract resources needed to carry out project.
Timeline	2006 to 2010
Who	Master planned community developers and builders. Impacted electric utility, Power Systems Engineering Center, building and community design experts, municipal planners
Potential Key Milestones	• Alliance formed, project site designated and design parameters complete (2006) • Utility modeling, analysis complete (2007) • Building/community aesthetic and structure analysis complete. Economic analysis completed (2007) • Interconnection, storage, energy control and demand side management strategies developed (2008) • Community pilot scale effort initiated (2008). Completed (2010)

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Forming a coalition of utilities to develop a large scale central solar project can provide certainty to stimulate investment.

Central Station Solicitation Action Plan	
Action/Rationale	Form coalition with western utilities to develop large scale central solar projects in Arizona. Focus on a single significant scale project, e.g. 250 MW, to be solicited in 2007 and completed within four years. Develop cross state utility partnership model mimicking large nuclear and coal plants. Leverage Arizona's solar resource to benefit surrounding state RPS and solar obligations.
Barriers Addressed	High current costs; lack of local market; need to develop labor skills; competition with Germany, California, etc. for attention of solar investors; difficulty of financing solar stations; current resource RFPs are not well suited for emerging technologies because of their costs, risks and development time-fame
Potential Risks	Do not get good quality bids. Planned acquisitions do not take place. Getting locked into long-term, high-priced contracts. Lack of adequate transmission capacity.
Timeline	2007-2011
Who	Utilities, ACC, Governor, Legislature
Potential Key Milestones	• Develop utility coalition (utilities, 2006 – 2007) • Provide political support for project (Governor, Legislature, 2007) • Identify and approve funding (ACC, 2007) • Large scale (250 MW +) plants built (2011)

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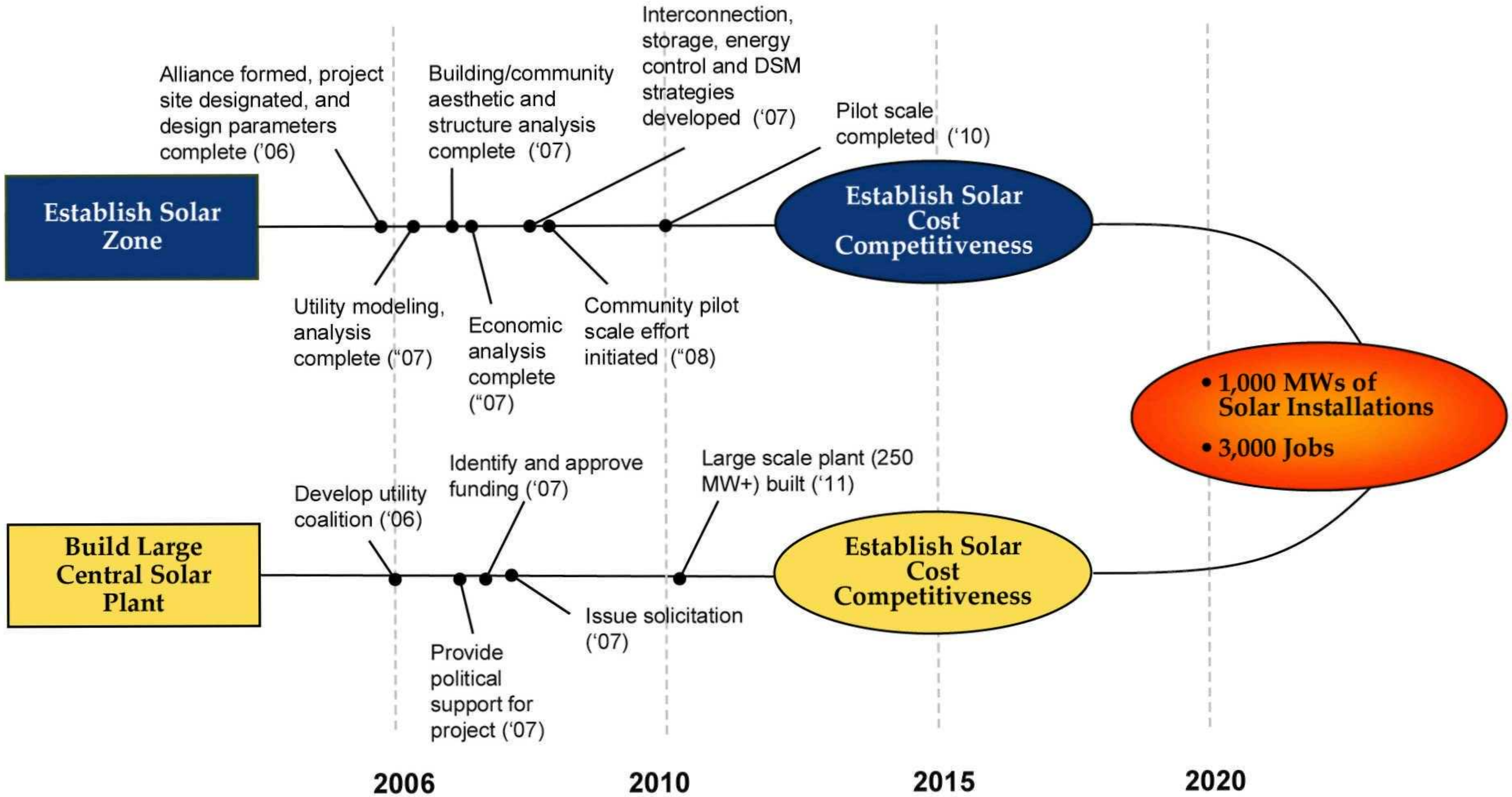
Below are key milestones to help accelerate the development and adoption of solar.



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Providing high profile visibility for solar utilization, development, and/or investment may also stimulate demand for solar.

Sustainable Partners Action Plan	
Action/Rationale	Prestigious recognition and awards that businesses display for solar utilization, development, or investments. Incorporate with Governors Innovation Awards and other high profile events. Awards provided at annual high profile banquet with the Governor. Awardees can use Sustainable Partner logo in their place of business and in advertisements. This program stimulates the demand for solar, making it a matter of being a good corporate citizen or showing environmental leadership. This stimulates commitment from corporate senior leadership.
Barriers Addressed	Lack of local markets, competition from other regions.
Potential Risks	No one elects to join. Insufficient political support.
Timeline	2007-2010
Who	Governors office, ADOC Energy Office
Potential Key Milestones	• Design program, logo, criteria, promotional campaign (1st half of 2007) • Launch initiative (2nd half of 2008)

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Incentive packages need to be developed for a marketing and outreach to lure key solar players to the state.

AZ Solar Marketing and Outreach Action Plan	
Action/ Rationale	Campaign to market AZ to solar manufacturers and national retail chains. Provide state incentive package that is comparable to other states/countries e.g. tax holidays for state investment or seed money to locate company in state.
Barriers Addressed	Many AZ programs and incentives have recently been expanded and the industry needs to be aware of these. Need to distinguish AZ apart from CA, NM or even Germany where incentives lure players.
Potential Risks	AZ tax payers perception of the program being a waste of money.
Timeline	2006 – on-going
Who	Arizona Department of Commerce
Potential Key Milestones	• Define lead within Department. of Commerce (2006) • Identify and prioritize opportunities to target (2007) • Develop incentive package for central solar developers, big box stores, and manufacturers or developers/installers wanting to locate in AZ (2007) • Talk with key solar players interested in locating in AZ (2007) • Develop summary of gaps and educate key stakeholders, as needed (2008)

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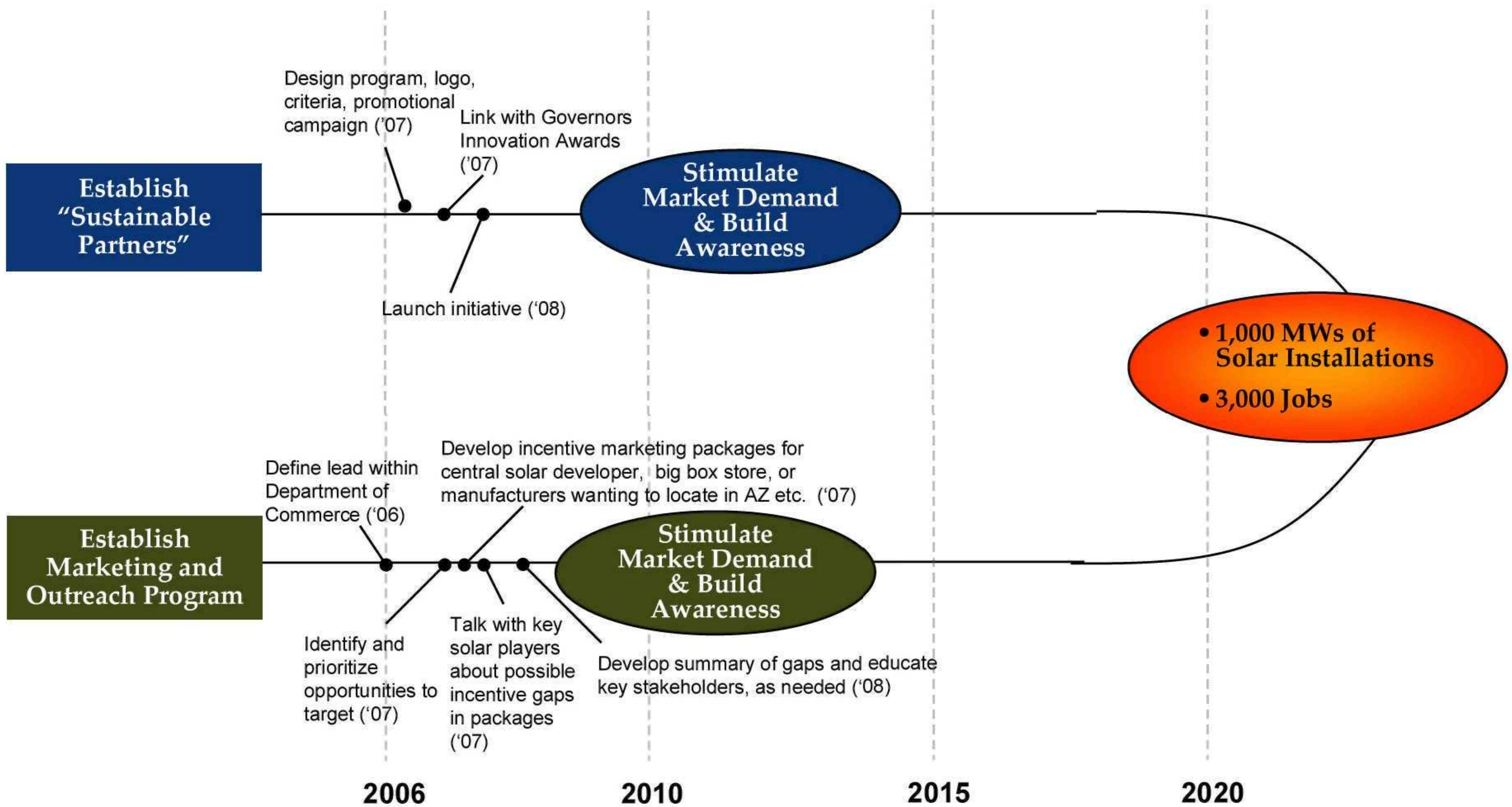
Below are additional key milestones for development and adoption of solar through stimulating market demand and building awareness.



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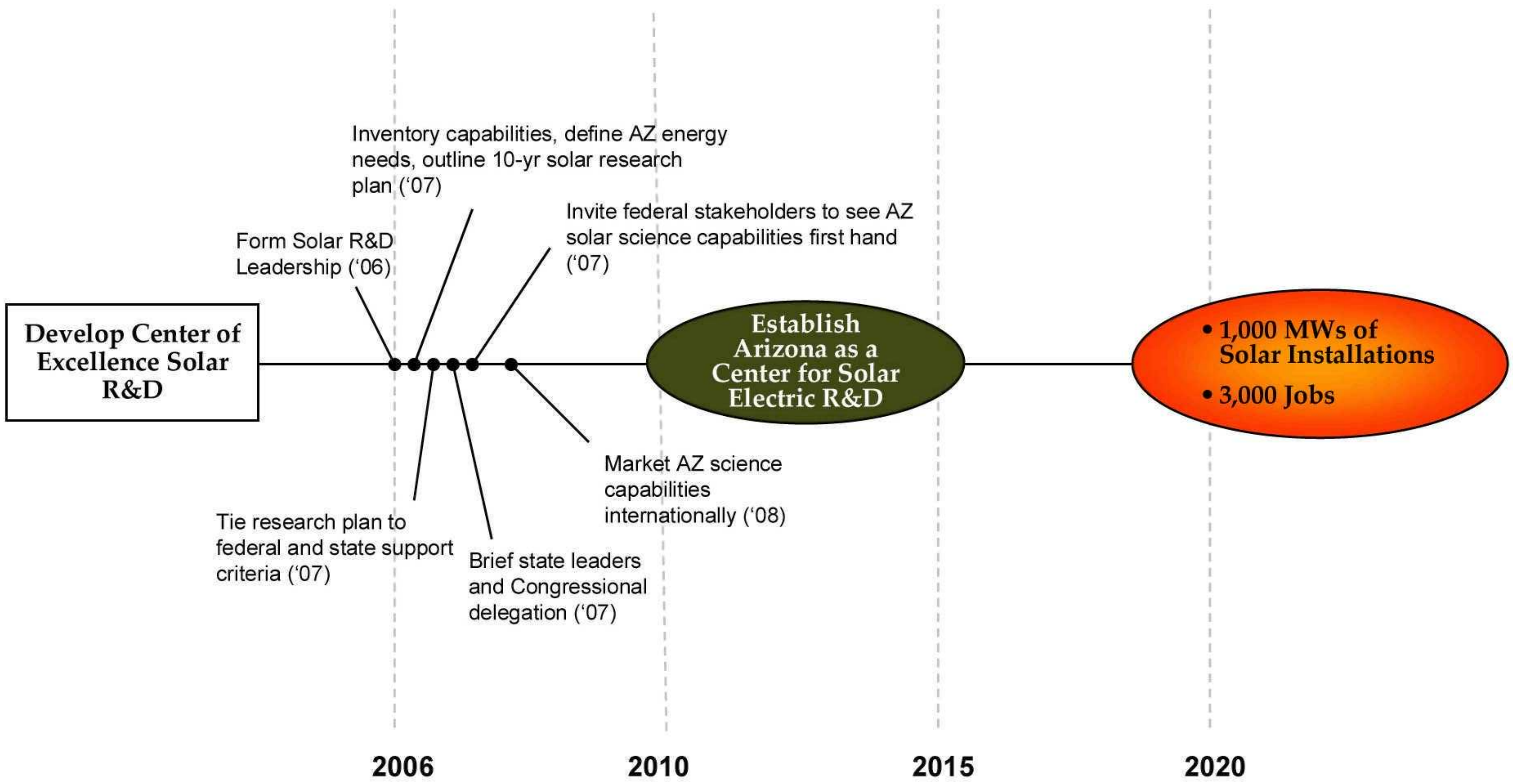
PUC-IR-304
DOCKET NO. 2008-0273
ATTACHMENT 2
PAGE 168 OF 189

AZ might consider the development of a Solar Center of Excellence to help establish itself as a leader in solar intellectual capital.

Establish Arizona as Leader in Solar Intellectual Capital Action Plan	
Action/ Rationale	Build solar Center of Excellence using existing expertise at STAR, ASU's Photovoltaic Testing Laboratory, together with science/technology strengths at ASU and UA. Define both near-term research strengths in solid state sciences, flexible display, power engineering and sustainable design; as well as longer-term strengths in light based bioscience and very high efficiency materials. Leverage federal funding using state resources from Science Foundation Arizona, approved utility R&D funding and new funding from the legislature. Using solar resource with scientific capabilities, AZ can lead the world in sustainable solutions for hot desert climates.
Barriers Addressed	Solar cost barriers in the short term, and limitations on carbon for energy production in the longer term.
Risks	Failure to attract state and private funds to build, package, and market AZ scientific capabilities.
Timeline	2007 - 2015
Who	State universities, state utilities, Science Foundation Arizona, ACC, AZ Legislature and congressional delegation
Potential Key Milestones	• Form Solar R&D Leadership Group (2006) • Inventory capabilities, define AZ energy needs, outline 10-year solar research plan (2007) • Tie research plan to federal and state support criteria (2007) • Brief state leaders and congressional delegation (2007) • Invite federal stakeholders to see AZ solar science capabilities first hand (2007) • Market AZ science capabilities internationally (2008)

Below are the key milestones for building knowledge to support the development of a Center of Excellence for Solar R&D.



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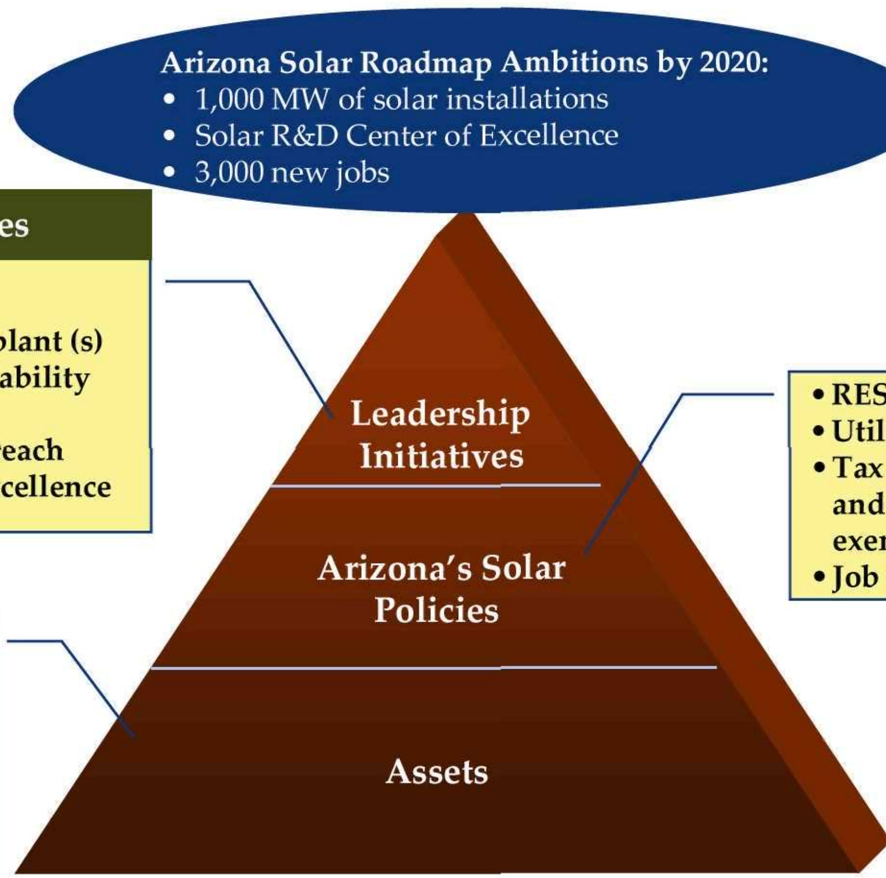
Implementing the roadmap initiatives will allow AZ to build upon its assets and policies to establish a leadership position in fostering solar.



Roadmap Initiatives

- Establish solar zones
- Build large central station plant (s)
- Establish "Arizona Sustainability Partners"
- Establish marketing & outreach
- Develop Solar Center of Excellence

- RES requirements
- Utility programs
- Tax credits (including sales and property tax exemptions)
- Job training funds

- Best solar resource in nation
- Rapidly growing markets
- Region committed to sustainable development
- Pro-business environment
- Intellectual capital at post-secondary institutions

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Table of Contents

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NCI's Levelized Cost of Electricity (LCOE) model computes electricity costs at the busbar level.

NCI's Levelized Cost of Electricity (LCOE) Model

- 25-year cash flow model
- Estimates all costs associated with a project, (e.g. capital, O&M, fuel and taxes), and discounts all costs to the present at the cost of equity and then computes a levelized cost in constant dollars
- The LCOE is the required selling price to cover all project cost over the project life, expressed in constant dollars (i.e., the revenue requirement). Focuses on costs, not market prices.
- LCOE is for busbar cost – does not include transmission and distribution.
- Includes the effects of Federal and state incentives (e.g., Federal Investment Tax Credit, accelerated depreciation, production tax credit, property tax exemptions)

The NCI LCOE model has six primary calculation steps that drive the cost of electricity results.

NCI LCOE Model - Primary Calculations

		Calendar Year / Year #	2010 / 0	2011 / 1	2012 / 2
Energy Production					
Energy produced each year	kWh/yr	297,840,000		297,840,000	297,840,000
COE ANALYSIS					
Cost cash flows (+ = outflow, - = inflow) (Nominal Dollars)		**Discount factor**	1.000	0.855	0.731
		NPV (base year$)			
Initial capital	$	52,000,000	57,398,270		
Replacement capital	$	0		0	0
Debt Service	$	54,153,007		[illegible]	[illegible]
Land Cost	$	0	0		
Operating expenses (less property tax and fuel)	$	27,816,258		[illegible]	[illegible]
Property tax	$	8,375,138		2,066,338	1,980,240
Fuel	$	0		0	0
Income tax	$	20,032,529		2,145,933	283,476
Rebate	$	0	0		
Accelerated depreciation	$	(20,561,283)		(11,590,035)	(17,385,053)
Low-interest loan	$	0		0	0
Property tax exemption	$	0		0	0
Production tax credit	$	(45,153,813)		(9,850,144)	(10,096,398)
Renewable energy production incentive	$	0		0	0
Corporate investment tax credits	$	0		0	0
Cogeneration Credit	$	0		0	0
Renewable Energy Certificates	$	0		0	0
Less...	$	0			
Total cash flow			**57,398,270**	**319,143**	**(7,570,720)**

LCOE (base year$)		LCOE (base year$)	Annuity (base year$)
Initial capital	$/kWh	0.0256	7,635,538
Replacement capital	$/kWh	0.0000	0
Debt Service	$/kWh	0.0267	7,951,680
Land Cost	$/kWh	0.0000	0
Operating expenses (less property tax and fuel)	$/kWh	0.0137	4,084,464
Property tax	$/kWh	0.0041	1,229,782
Fuel	$/kWh	0.0000	0
Income tax	$/kWh	0.0099	[illegible]
Rebate	$/kWh	0.0000	0
Accelerated depreciation	$/kWh	(0.0101)	[illegible]
Low-interest loan	$/kWh	0.0000	0
Property tax exemption	$/kWh	0.0000	0
Production tax credit	$/kWh	(0.0223)	(6,630,263)
Renewable energy production incentive	$/kWh	[illegible]	0
Corporate investment tax credits	$/kWh	[illegible]	[illegible]
Cogeneration Credit	$/kWh	[illegible]	[illegible]
Renewable Energy Certificates	$/kWh	[illegible]	0
Less...	$/kWh	0.0000	0
TOTAL	**$/kWh**	**0.0477**	**14,193,561**

2 → 25 years

3

4

5

Illustrative

Primary Calculations - Descriptions

1. Assumes an annual revenue stream (not shown in figure on the left) in ¢/kWh to allow the model to calculate an initial tax estimate.
2. Forecasts 25 years of cost cash flows for several cost categories (e.g., capital, debt, fuel, taxes).[1]
3. Calculates the Net Present Value of each cost item by discounting annual flows by the discount rate of the owner.
4. Calculates the equivalent annuity (levelized cost) for each category based on the owner's discount rate.
5. Divides the levelized costs (annuity) by the annual energy output in kWh to calculate the first estimate of the LCOE in ¢/kWh.
6. Iterates until the LCOE calculated in step 5 equals the assumed revenue required in step 1. This is the revenue required to cover the costs and return on capital required by the owner.

1. Separate sections of the model calculate the annual flows for each category based on inputs regarding incentives, technology costs, cost of capital.

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Table of Contents

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Information regarding Dish Stirling in Design News, *Sun Rises on Solar*, January 9, 2006.

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PV output of flat vs. latitude tilt and solar access issues based on interview with Ed Kern, Irradiance, May 2006.

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Renewable Energy World, *Concentrating PV Prepares for Action*, Volume 8, September –October 2005 Issue.

Fraunhofer Institute, *Concentration PV for Highest Efficiencies and Cost Reduction,* June 2005.

BTM Consult aps, *International Wind Energy Development, Wind Energy Update*, March 2006.

Robert Poore, President, Global Energy Concepts, Interview regarding wind turbine capacity factors, 2005.

Interview with Herb Hayden, Arizona Public Service, for information on STAR and concentrating solar technology performance, July 2006.

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Several references were used for this project.

Information on parabolic trough and dish Stirling costs based on interview with Hank Price and Mark Mehos, National Renewable Energy Laboratory, June 2006 as well as input from Bob Liden, Executive VP, Stirling Energy Systems, September 19, 2006.

Information on retail electricity rates in Arizona based on interview with Chico Hunter of Salt River Project, May 2006 and confirmed by utility Steering Committee members, September 2006.

For information on APS solar programs, interview with Herb Hayden and Peter Johnston, June 2006 and email from Barbara Lockwood, September 2006.

Information on gas prices from the Energy Information Administration, 2006 and EEA, 2006.

Information on renewable energy project locations from Energy Velocity, 2006.

Economic Energy and Environmental Benefits of Concentrating Solar Power in California, Black & Veatch, NREL/SR-550-39291, April 2006.

Barrier and opportunity information from manufacturers were based on interviews with BP, Sharp, and a large semi-conductor company, May and June 2006.

Barrier and opportunity information from Arizona Corporation Commission based on interviews with Chairman Hatch-Miller, Kris Mayes, and Ray Williamson, June 2006.

Barrier and opportunity information from Tribes based on interview with Inter-Tribal Council representative – Dave Castillo, June 2006.

Barrier and opportunity information from builders based on interviews with Pulte Homes, June 2006.

Finding Your Dream Job in Solar, Solar Today, October 2005.

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Renewing the Arizona Economy, Arizona Public Interest Research Group, 2005

Harnessing the Arizona Sun: Economic Growth Opportunities and Workforce Preparation Needs for the Solar Industries, Prepared by the Council for Community & Economic Research for the Arizona Department of Commerce, December 2005.

Analysis of Renewable Energy Survey Related to Business Uses, Prepared by Elliott D. Pollack & Company for the Arizona Department of Commerce, February, 2006.

Table of Contents

The various acronyms used throughout this document are defined below.

Acronyms	Definitions
ACC	Arizona Corporation Commission
ADG	Anaerobic Digester Gas
APS	Arizona Public Service
ASU	Arizona State University
BIGCC	Biomass Integrated Gasification Combined Cycle
CERB	Commercial and Existing Residential Buildings
CPV	Concentrating Photovoltaics
CSP	Concentrating Solar Power
DSM	Demand Side Management
GHG	Greenhouse Gas
IRP	Integrated Resource Plan
kW	KiloWatts
kWh	KiloWatt-hours
LCOE	Levelized Cost of Electricity[1]
LFG	Landfill Gas
MACRS	Modified Accelerated Cost Recovery System
MSW	Municipal Solid Waste
MW	MegaWatt
MWh	MegaWatt-hours
NCI	Navigant Consulting, Inc.
NREL	National Renewable Energy Laboratory

Acronyms	Definitions
PPA	Power Purchase Agreement
PTC	Production Tax Credit
PV	Photovoltaic(s)
REC	Renewable Energy Certificate
RES	Renewable Energy Standard
REPI	Renewable Energy Production Incentive
RNCC	Residential New Construction Component
RPS	Renewable Portfolio Standard
SAI	Solar America Initiative
SBC	System Benefit Charges
SRP	Salt River Project
TEP	Tucson Electric Power
UA	University of Arizona

1. The LCOE is the total lifecycle cost, expressed in real (constant) dollars, of producing electricity from a given project. It includes all the capital charges, fuel, and non-fuel O&M costs over the economic life of the project. Annual capital charges are computed based on the discount rate, cost of equity, debt/equity ratio, tax rate, depreciation schedule, property tax and insurance requirements. Thus the annual capital charges will vary significantly for different entities such as municipal utilities vs. private developers.

Definitions of selected terms are presented below.

Base Load	The minimum load experienced by an electric utility system over a given period of time.
Capacity Factor	The ratio of the average load on a machine or equipment for a period of time to the capacity rating of the machine or equipment.
Coincidental Peak Load	Two or more peak loads that occur at the same time.
Demand (electric)	The rate at which electric energy is delivered to or by a system, part of a system, or a piece of equipment. Demand is expressed in kW, kVA, or other suitable units at a given instant or over any designated period of time. The primary source of "demand" is the power-consuming equipment of the customers.
Distributed Generation	A distributed generation system involves small amounts of generation located on a utility's distribution system for the purpose of meeting local (substation level) peak loads and/or displacing the need to build additional (or upgrade) local distribution lines.
Fuel Escalation	The annual rate of increase of the cost of fuel, including inflation and real escalation, resulting from resource depletion, increased demand, etc.
Gigawatt	This is a unit of electric power equal to one billion Watts, or one thousand megawatts – enough power to supply the needs of a medium-sized city.
Grid	Matrix of an electrical distribution system.
Independent Power Producers (IPPs)	These are private entrepreneurs who develop, own or operate electric power plants fueled by alternative energy sources, such as biomass, cogeneration, small hydro, waste-energy and wind facilities.
Intermittent Resources	Resources whose output depends on some other factory that cannot be controlled by the utility (e.g., wind or sun), thus the capacity varies by day and by hour.
Investor-Owned Utility (IOU)	An IOU is a form of electric utility owned by a group of investors. Shares of IOUs are traded on public stock markets.
Kilowatt-Hour (kWh)	The basic unit of electric energy equal to one kilowatt of power supplied to or taken from an electric circuit for one hour.
Levelized	A lump sum that has been divided into equal amounts over a period of time.

Definitions of selected terms are presented below (continued).

Load Forecast	Estimate of electrical demand or energy consumption at some future time.
Load Profile	Information on a customer's usage over a period of time, sometimes shown as a graph.
Megawatt	One million Watts.
Megawatt-hour (MWh)	One thousand kilowatt-hours or one million-watt hours.
Off-peak	Periods of relatively low system demands.
Payback	The length of time it takes for the savings received to cover the cost of implementing the technology.
Peak Demand	Maximum power used in a given period of time.
Peaking Unit (Peakers)	A power generator used by a utility to produce extra electricity during peak load times.
Power Purchase Agreement	This refers to a contract entered into by an independent power producer and an electric utility. The power purchase agreement specifies the terms and conditions under which electric power will be generated and purchased. Power purchase agreements require the independent power producer to supply power at a specified price for the life of the agreement. While power purchase agreements vary, their common elements include: specification of the size and operating parameters of the generation facility; milestones in-service dates, and contract terms; price mechanisms; service and performance obligations; dispatchability options; and conditions of termination or default.
REC	Renewable Energy Certificates are used to track the "cleaness" of a power generator vs. the kWhs or power generated. They convey the right to claim the attributes associated with electricity generated from a specific renewable facility and are used to demonstrate compliance with renewable portfolio standard rules and substantiate green power marketing claims. RECs can also be used for labeling/ disclosure purposes.

Table of Contents

NAVIGANT CONSULTING

Appendix D » Steering Committee

Name	Organization
Stephen Ahearn, Director	State Residential Utility Consumer Office
Bud Annan	Solar Energy Advisory Council
Chuck Backus, President	Arizona State University Research Park
Harvey Boyce, Director	Arizona Power Authority
Lee Edwards, CEO	BP Solar
Eric Daniels, President of Technology	BP Solar
Jonathan Fink, Vice President for Research & Economic Affairs	Arizona State University
Greg Flynn	The League of AZ Cities and Towns
Ed Fox, Vice President	Arizona Public Service
Barbara Lockwood, Renewable Energy Manager	Arizona Public Service
Peter Johnston, Manager Technology Development	Arizona Public Service
Chico Hunter, Senior Engineer	Salt River Project
Gail Lewis, Policy Advisor	Governor's Office

Appendix D » Steering Committee (continued)

Name	Organization
Robert Liden, Executive VP and General Manager	Stirling Energy Systems, Inc.
Doug Obal, Director of Financial Analysis	Stirling Energy Systems, Inc.
Larry Lucero, Manager of Government Affairs	Tucson Electric Power
Todd Madeksza	County Supervisors Association of Arizona
Willis Martin, Vice President of Land Acquisition – Phoenix Area	Pulte Homes
Fred DuVal, Member	Commerce and Economic Development Commission
Leslie Tolbert, Vice President of Research	University of Arizona
Joe Simmons, Chair of Department of Materials Science and Engineering	University of Arizona

NAVIGANT CONSULTING

Table of Contents

Appendix E » Department of Commerce Team

Name	Organization
Deb Sydenham, Assistant Deputy Director, Community Development	Arizona Department of Commerce
Lisa Danka, Assistant Deputy Director, Strategic Investment and Research	Arizona Department of Commerce
Kent Ennis, Research Manager, Strategic Investment and Research	Arizona Department of Commerce
Lori Sherill, Support Specialist, Community Planning	Arizona Department of Commerce
Jim Arwood, Director Energy Office	Arizona Department of Commerce
Martha Lynch, CPPB, Director of Procurement Services, Chief Procurement Officer	Arizona Department of Commerce
Deborah Tewa, Renewable Energy Tribal Energy Specialist	Arizona Department of Commerce

Content of Report

This report was prepared by Navigant Consulting Inc.[1] This report was prepared for the exclusive use of the Arizona Department of Commerce - that has supported this effort. The report summarizes our findings from an evaluation of solar opportunities in the state of Arizona. The work presented in this report represents our best efforts and judgments based on the best information available at the time that we prepared this report. Navigant Consulting, Inc. is not responsible for the reader's use of, or reliance upon, the report, nor any decisions based on the report. NAVIGANT CONSULTING, INC. DOES NOT MAKE ANY REPRESENTATIONS, OR WARRANTIES, EXPRESSED OR IMPLIED. Readers of the report are advised that they assume all liabilities incurred by them, or third parties, as a result of their reliance on the report, or the data, information, findings and opinions contained in the report.

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PUC-IR-305
Please provide a narrative explanation and supporting documentation for shipping costs to Hawaii assumed in all rates in the HECO Companies' proposed Tier 1 and Tier 2 Tariff and Agreement.

HECO Companies Response:

The shipping costs are assumed to be 5% of equipment costs. These Hawaii-specific shipping costs were from the Black & Veatch IRP-3 supply-side portfolio update report (May 2005). See reference in Appendix O, page 3-16 at the HECO website link shown below.

http://www.heco.com/portal/site/heco/menuitem.508576f78baa14340b4c0610c510b1ca/?vgnextoid=d1ee5e658e0fc010VgnVCM1000008119fea9RCRD&vgnextfmt=default&cpsextcurrchannel=1

PUC-IR-306
Please describe to what extent the rates in the HECO Companies' proposed Tier 1 and Tier 2 Tariff and Agreement utilized Hawaii-specific cost or performance information based on existing Hawaii solar PV and small wind projects. List any projects from which rates were derived and the PPA rates these projects receive.

HECO Companies Response:

As discussed on page 7 of HECO's "Schedule FIT Tier 1 and Tier 2 Tariff and Agreement" filed on January 7, 2010, estimated PV capacity factors using NREL's PV Watts 1 tool were compared to data from real Hawaii projects in the Sun Power for Schools program. The Sun Power for Schools program performance data was consistent with what was developed using PV Watts.

In order that the rate determination process could be as transparent as possible, the Hawaiian Electric Companies elected to use public data wherever possible. Public cost data for Hawaii-specific PV projects is not available, particularly specific PPA rates. As such, mainland PV capital costs were adjusted using Hawaii-specific labor and productivity premiums. In addition, as a part of the overall process, the parties, and the Hawaii Solar Energy Association and the Solar Alliance in particular, had the opportunity to review and comment upon the capital costs used and their suitability for Hawaii-specific projects.

Small scale wind project data points were also not publicly available. As previously discussed and detailed in the Companies' January 7th and January 21st submittals, the wind project benchmarking costs did include Hawaii specific tax laws, Hawaii specific labor and materials premiums and Hawaii specific freight/transport costs and excise taxes. The parties to the proceeding, in particular the Hawaii Renewable Energy Alliance, were allowed to review and comment upon the wind pricing inputs and these comments are reflected in the filings made in this proceeding.

PUC-IR-307

According to page 9 of the HECO Companies' proposed Tier 1 and Tier 2 Tariff and Agreement

> "The midpoint of Tier 2 total installed cost is roughly $2000/kW. To incorporate the full range of project costs, E3 also assessed costs on installed in-line hydro units in Hawaii. All three projects identified in the State have additional construction costs which represent an undefined portion of the total cost. Thus, the costs shown should represent a conservative high end. The actual installed projects do not show the clear economies of scale relationship seen in the cost of generation analysis. Other factors seem to drive the installed cost in these three cases-most likely siting/development-related costs."

Please provide a full and detailed narrative explanation for your assumption that whatever factors driving the higher-than-expected installed capacity costs for past projects will not recur with future projects. On what basis do you conclude that these costs are anomalous?

HECO Companies Response:

The Companies have taken into account the costs of these known projects installed on the Island of Hawaii by including the data points in the analysis. Based upon the analysis discussed above in the information request, it is apparent that the projects represent the high end of potential installed costs. These projects include additional non-project related construction costs as discussed with Mike Maloney from SOAR Technologies who is familiar with these installations. Please see the details of these projects provided in the table below. Accordingly, while it was determined to be reasonable to include the average cost of these three installed projects to indicate a high end data point, there was not sufficient data to conclude that these projects would be typical of projects which may come on-line through the FIT Program.

SUMMARY OF HAWAII COUNTY IN-LINE HYDRO INSTALLATIONS AND OUTPUTS						
Customer	**Type**	**Size kW**	**Rate Schedule**	**Est. Amount**	**$/kW**	**Comments**
Department of Water Waimea Treatment Plant	In-Line Hydro - Pelton	36	Schedule Q	$250,000	$6,944	Installed cost were higher due to additional construction needs related to existing water system
Department of Water Kaloko	In-Line Hydro (micro turbine) - Pelton Unit	45	Schedule Q	$500,000	$11,111	Installed cost were higher due to additional construction needs related to existing water system
Department of Water Kahaluu Shaft	In-Line Hydro (micro turbine) - Pelton Unit	45	Net energy metering	$480,000	$10,667	Installed costs were higher ($620,000) due to using a design calling for two in line hydro units--only one generating unit was installed. Additional construction needs may have also contributed to the cost.

Source: Mike Maloney, SOAR Technologies, (425) 861-8870, Woodinville, WA

PUC-IR-308
Why are the Tier 1 CSP low and high LRDC figures in the first paragraph of page 11 of the HECO Companies' proposed Tier 1 and Tier 2 Tariff and Agreement the same as those in the third paragraph of page 11 , which assume the use of the 24.5% refundable state tax credit?

HECO Companies Response:

The LCOE cost range in the third paragraph is incorrect. The third paragraph on page 11 of the HECO Companies' proposed Tier 1 and Tier 2 Tariff and Agreement should read as follows:

"It may be appropriate for CSP projects to also avail themselves of the 24.5% refundable state tax credit. With this assumption the LCOE for Tier 1 CSP projects ranges from **$272/MWh on the low end to $390/MWh** on the high end with installed costs between $8,500/kW and $10,600/kW. $331 is the midpoint of the range and is the proposed FIT rate for Tier 1 CSP projects utilizing the 24.5% refundable tax credit."

PUC-IR-309
With respect to the third paragraph on page 11 of the HECO Companies' proposed Tier 1 and Tier 2 Tariff and Agreement, why is the midpoint of the Tier 1 range of the project LCOE higher than the "high" LCOE? Please clarify the correct figures in the paragraph, including the midpoint of the range, and clarify what assumptions are correct.

HECO Companies Response:

The LCOE cost range in the third paragraph is incorrect. The midpoint stated is correct. The third paragraph on page 11 of the HECO Companies' proposed Tier 1 and Tier 2 Tariff and Agreement should read as follows:

"It may be appropriate for CSP projects to also avail themselves of the 24.5% refundable state tax credit. With this assumption the LCOE for Tier 1 CSP projects ranges from **\$272/MWh on the low end to \$390/MWh** on the high end with installed costs between \$8,500/kW and \$10,600/kW. \$331 is the midpoint of the range and is the proposed FIT rate for Tier 1 CSP projects utilizing the 24.5% refundable tax credit."

PUC-IR-310
Why did page 11 of the HECO Companies' proposed Tier 1 and Tier 2 Tariff and Agreement assume a 20-year debt term? Please provide evidence that this is the typical debt term for Tier 1- and Tier 2-sized projects.

HECO Companies Response:

The debt term was assumed to be 20 years to match the term of the FIT Agreement, which is consistent with the guiding principles set forth in the Commission's September 25, 2009 Decision and Order, incorporates a twenty year contract term. One of the purposes of the FIT is to reduce the risk associated with raising financing for the projects. Based upon discussions with industry representatives and project information available to the pricing development team, a 20-year debt tenor was chosen. The assumptions were also discussed with the other parties to the FIT proceeding during the technical pricing workshop held in November, 2009, and they did not disagree.

PUC-IR-311

According to Section 6(b) of the HECO Companies' proposed Tier 1 and Tier 2 rates:

(b) The Company shall not be required to purchase energy during any period during which, due to operational circumstances, purchases from the Seller will result in costs greater than those which the Company would incur if it did not make those purchases, but instead, generated an equivalent amount of energy itself. The Company shall provide the Seller with at least twenty-four (24) hours advance oral or written notice of any such period to allow the Seller to cease the delivery of energy to the Company. The Company and the Seller will work to develop a mutually acceptable format for this notice, including, but not limited to, a listing of typical parameters that define anticipated constraints in purchases from the Seller. If the Company fails to provide such notice, it will pay the same rate for such purchase of energy as would be required had the period not occurred. Without limiting the foregoing, conditions when curtailment of energy delivery by the Seller maybe implemented by the company may include when, during excess energy conditions, the Company would have to (i) cycle off-line any Base Load Unit, or (ii) remove one or more components of a combined cycle unit (such as shutting off one combustion turbine or one combustion turbine and the steam turbine of a dual-train combined cycle unit (consisting of two combustion turbines and one steam turbine» in order to purchase energy from the Seller. The Company shall not curtail pursuant to this Section 6(b) of the Agreement solely as a consequence of the Company's filed Avoided Energy Cost Data being lower than the applicable energy payment rate paid to the Seller under this Agreement.

(a) Do any Commission regulations or portions of the D&O in this docket authorize HECO to curtail as-available renewable resources for economic reasons? Please cite any such provisions.

(b) Do the HECO Companies currently curtail renewable energy units for economic reasons? If so, describe (1) the reasons for such curtailment, (2) what units are typically curtailed, and (3) the frequency of such curtailment.

(c) How did the HECO Companies factor potential curtailment into the capacity factor data used to calculate rates? What percentage of otherwise available hours for each technology and size tier do the HECO Companies project that they would curtail?

<u>HECO Companies Response:</u>

The citation is from Section 6(b) of the HECO Companies' proposed Schedule FIT Tier 1 and Tier 2 Agreement. This Section is drafted to conform to similar sections in power purchase agreements ("PPA") negotiated between a HECO Company utility and an independent power producer, and which were approved by the Commission. (See, for example the MECO-Kaheawa Wind Power, LLC PPA, Section 6(b), approved by the Commission in D&O No. 21701 in

Docket No. 04-0365; and the MECO-Lanai Sustainability Research, LLC PPA, Section 6(b), approved by the Commission in a Decision and Order dated October 31, 2008 in Docket No. 2008-0167.) This is consistent with the following direction from the Commission's September 25, 2009 Decision and Order ("Decision and Order"): "[e]xcept where the commission has dictated specific terms and conditions, the terms and conditions of the standard offer contracts should, to the extent possible, closely match those of existing negotiated PPAs." (Decision and Order at 87).

(a) The authorities for Section 6(b) of the proposed Schedule FIT Tier 1 and Tier 2 Agreement, and for similar sections in previously approved PPAs are Hawaii Administrative Rules Title 6, Chapter 74, Section 6-74-24 (Periods during which purchases not required), 18 CFR Part 292, Section 292.304(f) (Periods during which purchases not required), and Federal Energy Regulatory Commission Order No. 69 (Final Rule Regarding The Implementation Of Section 210 Of The Public Utilities Regulatory Policies Act Of 1978). The HECO Companies interpret these authorities as not allowing the utility to curtail as-available renewable resources for economic reasons. This is consistent with Section 6(c) of the proposed Schedule FIT Tier 1 and Tier 2 Agreement which expressly provides that Section 6 "is not intended to permit the Company to require the Seller to curtail, interrupt or reduce deliveries of energy based on the Company's economic dispatch (for example, as a consequence of the Company's filed Avoided Energy Cost Data being lower than the applicable energy payment rate paid to the Seller under this Agreement, or to make purchases of less expensive energy from a Qualifying

Facility or other facility)."

(b) No. The PPAs for as-available renewable energy facilities do not have provisions for curtailment of output for economic reasons.

(c) The HECO Companies did not factor potential curtailment into the capacity factors used to calculate rates. Additionally, through its Decision and Order at Page 71, the Commission stated that it "will not establish a compensation mechanism for curtailment of FIT projects at this point in time. The commission may revisit the curtailment issue during any subsequent periodic reexamination of the FIT process."

PUC-IR-312

According to the HECO Companies' Tier 1 and Tier 2 proposal:

> "The energy payment rates specified in paragraph G(I) are based on the 35% Hawaii state renewable energy technologies income tax credit as prescribed in the Hawaii state tax code, Hawaii Revised Statutes ("HRS") Section 235-12.5. If the Seller provides written documentation at the time of application under this Schedule FIT that the Seller will elect the tax credit refund provision for solar energy technologies as provided in HRS Section 235- 12.5(g), and prior to the Commercial Operation Date provides a copy of the actual tax filing to the Sate Department of Taxation documenting this election, the Company shall pay for each kilowatt-hour ("kWh") of electric energy delivered to the Company by Seller as follows."

According to DBEDT's website:

Available Tax Credits

Solar Thermal System (solar water heaters) 35% tax credit	**Effective Date** Installed and placed in service after July 1, 2006

Single family residential property: 35% of actual cost or $2,250, whichever is less.

Multi-family residential property: 35% of actual cost or $350 per unit, whichever is less.

Commercial property: 35% of actual cost or $250,000, whichever is less.

Wind System 20% tax credit	**Effective Date** Installed and placed in service after July 1, 2006

Single family residential property: 20% of actual cost or $1,500, whichever is less.

Multi-family residential property: 20% of actual cost or $200 per unit, whichever is less.

Commercial property: 20% of actual cost or $500,000, whichever is less.

Photovoltaic (PV) System 35% tax credit	**Effective Date** Installed and placed in service after July 1, 2006

Single family residential property: 35% of actual cost or $5,000, whichever is less.

Multi-family residential property: 35% of actual cost or $350 per unit, whichever is less.

Commercial property: 35% of actual cost or $500,000, whichever is less.

Multiple owners of a single system (solar thermal, PV, or wind) are entitled to a single tax credit that shall be apportioned between the owners in proportion to their contribution to the cost of the system.

Many residential solar PV projects cost roughly $30,000, so the tax credit, which caps at $2,250 for single-family homes, would not cover 35% of total costs as calculated (or even $24.5%). The same dynamic could occur for larger PV as well as wind systems. How do rate calculations consider caps on state tax credits?

HECO Companies Response:

The HECO price proposal was qualified to state that the 35% state tax credit was applied only to the calculation of PV and CSP FIT prices. A 20% tax credit was applied to wind systems and no tax credit was applied to in-line hydro systems. For PV pricing purposes, it was assumed that customers (including residential customers) who install PV systems will design and install a sufficient number of inverters to obtain the maximum credit of 35% since each PV panel/inverter system constitutes an independent energy generating system subject to the credit cap per the Hawaii State Department of Taxation. FIT pricing for commercial wind systems included only a single cap of $500,000.

PUC-IR-313

According to page 62 of the D&O:

> "In reviewing the record, the commission finds that FIT rates 'should support a typical or average project that is reasonably cost-effective... "
> According to page 9 of the HECO Companies' Tier 1 and Tier 2 FiT proposal:
> "For Tier 1 projects with a capacity factor higher than 26%, which targets better wind sites and more cost effective projects, the LCOE ranged from $117/MWh on the low end to $205/MWh on the high end with installed costs between $5000/kW and $7000/kW and capacity factors between 26-32% (with losses included). $ 161 is the midpoint of the range and is the proposed FIT rate for Tier 1 wind projects... The definition targets low environmental impact hydro projects. Selecting the middle range of capacity factor focuses the rate on more cost-effective opportunities."
> (emphasis added)

Provide comparative calculations for average projects.

<u>HECO Companies Response:</u>

The pricing analyses conducted by the Companies were designed to utilize capacity factors which target average or typical projects that take advantage of the wind resources that are available in Hawaii. Hawaii has abundant wind resources at or above class 3/4 wind as defined at a 30m hub height. The Companies' initial analysis considered a full range of installed costs, operating costs, capacity and other factors. In order to ensure that FIT projects would also be reasonably cost effective, it was necessary to narrow the range based on key sensitivity factors. This included excluding low capacity factor wind projects with non-typical wind resources for Hawaii which would increase the overall FIT rate and unnecessarily provide excessive profits to some project developers at the expense of ratepayers.

The definition of an in-line hydro project was developed collaboratively by the FIT parties to be "hydroelectric generation that utilizes energy from a water pipeline system that is designed primarily to serve another functional purpose where a section of pipeline is replaced with a turbine generator section. In-line hydroelectric generation does not include (a) pumped storage hydroelectric generation, (b) run of the river hydroelectric generation or (c) any system using the energy from water from a new (after January 1, 2009) diversion from any river or stream." This definition targets low environmental impact hydro projects. The middle range capacity factor (in-line hydro capacity factors range from 10-90%) represents the average project. To be fair to rate payers, capacity factors below 50% should not be included as they would not be encouraging "typical", average, or reasonably cost effective projects.

PUC-IR-314
According to the HECO Companies' proposed Schedule FIT Tier 1 and Tier 2 Tariff and Agreement:

> "Except with the written consent of the Company, which consent shall not be unreasonably withheld, each physical address (defined as a single residential address or a single tax map key if a commercial or industrial facility) may not have more than one Facility of the same technology type contracted under this Schedule FIT."

Under what specific conditions would the HECO Companies allow or withhold consent for multiple facilities of the same type? Why is this "one facility" limitation necessary and in the public interest?

HECO Companies Response:

The primary reason for the "one facility" limitation is to avoid the situation where a developer otherwise capable of developing a single 500 kW project at a specific location at a Tier 2 rate, *instead seeks to develop 25 20 kW projects at the same location to take advantage of a higher* Tier 1 FIT rate. In discussions with the parties during the technical sessions in this proceeding, the parties largely agreed that this type of "gaming" should be prevented but also acknowledged, along with the Hawaiian Electric Companies, that this type of "anti-gaming" provision should not preclude developers that legitimately qualify under the FIT Program from developing projects. Because, after some discussion with the parties, it was recognized that it would be difficult to draft a provision which prevents gaming in every situation but also allows every legitimate development to go forward, the language cited above was developed. The goal of the provision would be to have a standard in place to restrict gaming but also provide the utility with the reasonable discretion to allow legitimate projects.

PUC-IR-315
According to the HECO Companies' proposed Schedule FIT Tier 1 and Tier 2 Tariff and Agreement:

> "Pursuant to Section 5 (Personnel and Company System Safety) and Section 6 (Continuity of Service) of the Agreement, the Company may at times have limited ability to integrate energy produced by the Seller into the Company System for engineering and/or operating reasons and may be required to curtail energy deliveries by the Seller."

Please provide a detailed list of the reasons for curtailment. Specify the reasons for which the HECO Companies have already curtailed renewable energy and which reasons are hypothetical.

HECO Companies Response:

Curtailments may be required for a number of reasons, including but not limited to the following: inability to accept energy due to system repairs/outages affecting the circuit to which the equipment interconnects; distribution or transmission system constraints such as voltage and/or power flow (ampere) limitations; management of the system during restoration and recovery from disturbances; power quality problems caused by the particular facility; and excess energy conditions when firm generation has been turned down or off to the extent allowable while still maintaining grid stability . Curtailments of renewable energy have been performed in actual operation for all of the foregoing reasons.

PUC-IR-316
According to the HECO Companies' proposed Schedule FIT Tier 1 and Tier 2 Tariff and Agreement:

"The Company shall install, maintain and periodically test such meters as the Company deems appropriate and shall be reimbursed by Seller for all reasonably incurred costs for such installation, maintenance and testing work."

(a) Do the HECO Companies currently assess such charges to (a) customers, or (b) interconnected facilities from whom they purchase power?

(b) Please estimate (a) the initial costs of meter installation, and (b) ongoing annual maintenance and testing work.

(c) Are the costs described in Part B above included in the calculation of rates? If so, please describe how they are incorporated. If not, describe why they have been omitted from such rate calculations.

HECO Companies Response:

(a)(a) Per HECO Tariff Rule-11 (A)(2), a customer may request the Company to test their meter at no charge provided it is limited to no more than once in a 12 month period.

(a)(b) Pertaining to the independent power providers (IPPs) from whom the Company purchases power, the Companies' power purchase agreements (PPA) with the providers call for the IPP to reimburse the Company for all reasonable costs associated with the annual meter replacement. These expenses include labor costs for meter programming, testing and for all field work needed to replace the meters.

(b)(a) Historically, the initial installation costs including material, labor, and Company overhead is approximately $5,600 (see attached calculations). This cost is based on the following assumptions:

1) That the Company will provide two high-end (Itron Q1000) revenue meters, where one is

designated as an "A" (or primary) meter and the second is designated as a "B" (or backup) meter.

2) The IPP supplies the associated instrument transformers (Current Transformers and Potential Transformers) necessary for the revenue metering application.

(b)(b) Historically the labor costs for IPP meter replacements have ranged between $1,200 and $2,000 and are based on the number of meters that must be tested and replaced.

(c) The initial costs of meter installation and ongoing annual maintenance and testing work were not included in the FIT Tier 1 and 2 rates. It was assumed that for the FIT Tier 1 and Tier 2 projects of 500 kW or less in size, the meter equipment and related costs would be borne by the HECO Companies, consistent with the practice with other energy purchase arrangements.

PUC-IR-317
According to the HECO Companies' proposed Schedule FIT Tier 1 and Tier 2 Tariff and Agreement:

> "Seller shall provide or cause to be provided to Company on a timely basis, as reasonably determined by Company, all information, including but not limited to information that may be obtained in any audit referred to below (the "Information"), reasonably requested by Company for purposes of permitting Company and Hawaiian Electric Industries. Inc. ("HEI") to comply with the requirements (initial and on-going) of (i) identifying variable interest entities and determining primary beneficiaries under the accounting principles of Financial Accounting Standards Board ("FASB") Accounting Standards Codification 810, Consolidation ("FASB ASC 810"); (ii) Section 404 of the Sarbanes-Oxley Act of 2002 ("S0X 404"); and (iii) all clarifications, interpretations and revisions of and regulations implementing FASB ASC 810 and SOX 404 issued by the FASB, Securities and Exchange Commission, the Public Company Accounting Oversight Board, Emerging Issues Task Force or other governing agencies."

(a) How could the above referenced reporting go beyond the reporting requirements listed in the Commission D&O? Provide a specific list as known or expected today.

(b) What specific information might the Company require of residential solar and wind project owners?

HECO Companies Response:

(a) The above referenced provision is our standard provision which we include in all of the HECO Companies' purchase power agreements. Under the accounting guidance of FASB ASC 810 (formerly FASB Interpretation No. 46R, as amended by FAS 167), HECO will be required to consolidate the financial records of an entity[1] in HECO's financial statements if HECO has a variable interest in the entity and if HECO is the primary beneficiary.

In addition, in the event HECO is required to consolidate the entity onto its financial statements, HECO will need to review the entity's system of internal controls over financial reporting, under the requirements of SOX 404, including allowing our external auditor to audit the entity's financial records. Among other things, SOX 404 requires our chief executive officer and chief financial officer to make certifications with respect to the Company's (including the entity's, should consolidation be necessary) system of internal controls over financial reporting.

(b) Sellers who are residential solar and wind project owners will not be required to provide information to HECO, in order to comply with the accounting guidance referenced above, unless these sellers have created a legal entity to contract with HECO. In the event that HECO will require information from an entity, Attachment A is an example of the information that we request of our independent power producers which we have executed power purchase agreements with.

It should be noted that HECO has completed a preliminary consolidation analysis on the draft FIT agreement and accompanying rate schedule, and has concluded that it does not appear that the FIT agreement would result in HECO having a variable interest in the entity that HECO contracts with, and as a result, HECO would not be the primary beneficiary and consolidation would not be necessary. However, the preliminary analysis and conclusion are based on the review of the draft FIT agreement and accompanying rate schedule, which has not yet been approved and finalized by the Commission. HECO plans to re-perform its analysis when the FIT agreement and accompanying rate schedule are approved by the Commission.

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1 For the purposes of applying the accounting guidance of FASB ASC 810, an entity is defined as a separate legal structure used to hold assets or conduct activities. Examples include corporations, partnerships, trusts, LLCs, LLPs etc.

Attachment A
Information Request List – May Not Be Complete

COMPANY/PARTNERSHIP INFORMATION

1. Original and latest amended Articles of Incorporation, partnership agreement or other governing documents
2. Current ownership structure (by party along with party's ultimate parent)
3. Information on all ownership and capitalization changes from inception to date
4. Information regarding the activities of the company, including the assets utilized in the operations, the processes necessary for normal self-sustaining operations, and outputs of the operations.
5. Information regarding activities of the Company which resulted in any of the following between inception to date:
    a. Change in entity's governing documents or contractual arrangement which result in change in partners investment at risk;
    b. Return of equity investment or some part thereof to the equity investors, and other interests becoming exposed to expected losses of the entity;
    c. Entity undertaking additional business activities or acquiring additional assets.
6. Puts/calls held by any party and details thereof
7. All material contracts (or summaries if the original contracts are not immediately available) of the Company in place since inception including side agreements, if any, but not limited to:
    a. Partnership/other equity-related agreements
    b. Debt and other borrowings documents;
    c. Material asset or stock acquisitions or dispositions;
    d. Documents under which guarantees or indemnities have been provided by the Company;
    e. Material supplier and customer contracts;
    f. Related party contracts and agreements;
    g. Documents related to material hedging activities;
    h. Contingent obligations and financial commitments;
    i. Leasing arrangements and off-balance sheet obligations;
    j. Management and Outsourcing contracts.

FINANCIAL INFORMATION

1. Complete Annual and Quarterly (if available) financial statements, including footnotes, from the inception of the power purchase agreement;
2. Descriptions of the following obligations, preferably annually and quarterly (if available), from the inception of the power purchase agreement:
    a. On-balance sheet obligations;
    b. Lease obligations and commitments;
    c. Off-balance sheet commitments;

Attachment A
Information Request List (continued)

   d. Contingent obligations;
   e. Collateral obligations.
3. Cash flow estimates, preferably quarterly, over the life of the Power Purchase Agreement;
4. The results of any evaluations that may have been made with respect to your Company's application of FASB ASC 810 to our agreement.

PUC-IR-318
According to the HECO Companies' proposed Schedule FIT Tier 1 and Tier 2 Tariff and Agreement:

"If any of the following conditions occur during the FIT Term, then the Company shall have the right to terminate this Agreement:

(ii) The Seller makes a general assignment for the benefit of its creditors;

(iii) The Seller files bankruptcy, has a petition for involuntary bankruptcy filed against it, or has a receiver appointed because of insolvency;

(iv) The Seller's dissolution or liquidation..."

Why should the HECO Companies have the right to terminate the Agreement in the event of the financial events listed above? What is the benefit to Hawaii ratepayers of such a right, and why would the HECO Companies or the ratepayers be harmed in its absence? Why would these contracts not be assigned to the HECO Companies' successor except as ordered by the Commission or bankruptcy court? Is this needed, or can the Commission or bankruptcy court make these decisions if insolvency occurs?

HECO Companies Response:

Through the Commission's September 25, 2009 Decision and Order in Docket No. 2008-0273, the Commission adopted twenty year contract terms for the FIT Program. (Decision and Order at 85). The Commission also determined that system caps for the initial FIT Program are an appropriate mechanism to limit potential ratepayer consequences and reliability impacts of a FIT Program. (Decision and Order at 54).

Each of the enumerated provisions discussed in the information request concerns a fundamental change in the financial condition of the Seller. The cited provisions are necessary to help assure that the utility, on behalf of its ratepayers, is not locked into a twenty year agreement with a Seller that may no longer be financially capable of appropriately operating and maintaining its facility and equipment and/or standing behind its' financial obligations (e.g. Indemnification, Insurance) under the Agreement. Additionally, due to the fact that there is a limited amount of available FIT Program capacity, it is beneficial for ratepayers to have only viable and efficient projects as a part of the Program. If a Seller is not able to appropriately maintain and operate its Facility, the utility should have the option of terminating the Seller's Agreement so that a financially sound Seller that is capable of reliably delivering energy may take its place.

As the provisions in question concern the insolvency or bankruptcy of the Seller, it is assumed that the third question in the information request pertains to a potential assignment of the Agreement to the Seller's successor. While this may be a possibility, this type of assignment would provide no further assurances to the utility or ratepayers that the successor to the Seller's contract will be able to reliably maintain and operate the Facility. The more prudent option, if the utility were to exercise the right to terminate, would be for the next eligible Facility which has been appropriately vetted and identified through the utilities' Queuing and Interconnection Procedures, to come on-line.

PUC-IR-319
Do the HECO Companies now curtail intermittent generators based on vintage, with newest generators curtailed first? If so, do the HECO Companies propose to continue this policy under their proposed feed-in tariff or move to a different policy? If not, in what order are generators currently curtailed and how, if at all, would that change under the feed-in tariff?

<u>HECO Companies Response:</u>

Curtailments that are necessary for reasons that directly affect or are attributable to a particular facility, are performed as necessary for the particular reason requiring the curtailment and are not based upon any priority order. For excess energy conditions, all facilities contribute to the excess energy situation and curtailments at this time are generally performed according to the chronological seniority of the non-appealable Commission order approving the contract with the most recent chronological seniority date being the first curtailed, and deliveries under such agreements with the earliest chronological seniority date being the last curtailed. Details of the curtailment order for the HECO Companies are discussed in the HECO Companies' response to ZEL-IR-107 (b) filed March 1, 2010 in the subject proceeding.

Under the feed-in tariff, it is proposed that sellers of energy may be curtailed for system reasons and those that are directly attributable to the facility. In the case of an excess energy condition, it is anticipated that FIT resources would be subject to a curtailment policy similar to that described above. The details of the specific curtailment policy are presently in development by the HECO Companies.

PUC-IR-320
Please describe any harm done to the HECO Companies or their ratepayers if project owners sell power elsewhere when they are curtailed.

HECO Companies Response:

If a FIT seller is curtailed because of excess energy on the system, it is because there is too little system load to accept any additional generation, even after the output of other generators has been reduced (as applicable.) The harm is that the sale of energy during this period may exacerbate the excess energy situation by further reducing system load, and require more generation connected to the system to be curtailed. Curtailment of resources depending on the type of resource may also further increase costs. If the energy sold is renewable and displaces other firm renewables or less costly renewables, there may be cost impacts. Also the reserves generation needed to accommodate additional variable renewables may also be impacted due to the higher level of resource curtailment.

PUC-IR-321
Please confirm or deny Solar Alliance's assertion that the SCADA trigger is now 1 MW but is proposed by MPC to be 0.5 MW and would also include "all other Facilities, regardless of size, where it is deemed, at the company's sole discretion, that an alternate means of curtailment is currently feasible." If so, please describe why the HECO Companies are changing the SCADA trigger and why it is necessary to have such procedures for projects below 1 MW.

HECO Companies Response:

One of the proposed modifications to Rule 14H filed in Docket No. 2010-0015 is to require SCADA for facilities larger than 0.5 MW for HECO and 0.25 MW for MECO and HELCO. The proposed amendment to modify the level at which SCADA will be required will allow the HECO Companies to have more visibility and control of FIT Tier 3 generating facilities where feasible (based on size of the interconnecting facilities). The HECO Companies have determined that with increasingly high penetration levels of variable generation, visibility and control is critical to the ability to determine necessary reserves, to control system balancing and frequency, and for system restoration. Requiring visibility and control will help mitigate the reliability impacts that are expected to occur with the anticipated large number of interconnected variable distributed generators that will come on-line through the FIT, Net Energy Metering and Standard Interconnection Agreements. The Companies' system operators need to maintain the balance of load to generation at all times. During system restoration procedures, balancing of the system is even more critical and the ability to control facilities of FIT Tier 3 size and larger will facilitate a more rapid return to full system operation. As more variable generators are added to the system, it is critical to have information on what these generation systems are producing in order for the system operator to control the frequency and voltage of the entire grid. This will ensure prompt response to system abnormalities and the ability to manage both variable resources and the Companies' own generating units.

PUC-IR-322
Please describe the service charges assessed to variously sized projects receiving power purchase agreements from the HECO Companies.

HECO Companies Response:

Most as-available PPAs which have been approved by the Commission include a $25.00 monthly service charge for the metering, billing, and administration of the Seller's purchased power under the PPA. The 30 MW Kahuku Wind PPA (Docket No. 2009-0176) and the 6.642 MW Honua PPA (Docket No. 2010-0010) also contain the same $25.00 monthly charge.

Monthly charges are slightly lower for Schedule Q agreements (Qualifying Facilities of 100 kW or less). As currently reflected in the Schedule Q tariffs for the Companies, the monthly service charges are $20 at HECO, and at MECO and HELCO $5 for single phase service and $10 for three phase service.

PUC-IR-323
Please describe the basis for the specific level of the $25-per-month service charge described in the HECO Companies' proposed Schedule FIT Tier 1 and Tier 2 Tariff and Agreement.

<u>HECO Companies Response:</u>

The proposed $25 per month service charge is the same as the amount provided for in other purchased power agreements for as-available energy. See also the response to PUC-IR-322. To confirm the reasonableness of the proposed amount, the Companies estimated the revenue requirement for a meter for this type of project. The calculation showed that on a levelized annual basis, the revenue requirement for the meter was $299, or approximately $25 per month.

PUC-IR-324
Was the $25 service charge included in the HECO Companies' Tier 1 and Tier 2 rate calculations? If not, why was this cost excluded? If so, how was it incorporated?

HECO Companies Response:

The $25 service charge was not included in the rate calculations. At the time that the FIT Tier 1 and Tier 2 pricing was being developed, the service charge had not been finalized. Once the Companies receive the Commission's order on the Companies' FIT Tiers1 and 2 Proposal, the Companies will be able to recalculate the rates to reflect the Commission's determination.

PUC-IR-325
Do the HECO Companies' proposed Schedule FIT Tier 1 and Tier 2 Tariff and Agreement require developers to pay for interconnection costs on the utility side of the interconnection? If so, please describe (a) which costs (including transmission upgrades, distribution upgrades, and storage) the developer is responsible for, and (b) how such interconnection costs are incorporated in rate calculations.

HECO Companies Response:

It is anticipated that typical FIT Tier 1 and Tier 2 projects will not require any upgrades on the utility side of the interconnection. If a particular project requires infrastructure upgrades then the developer will be responsible for the associated costs in accordance with Tariff Rule 14H. Because the initial FIT rates were developed using typical project assumptions, no interconnection costs related to the utility side of the interconnection were incorporated in the rate calculations.

PUC-IR-326
How are the interconnection requirements and cost allocation for the proposed Schedule FIT Tier 1 and Tier 2 Tariff and Agreement different from those typically borne by developers in negotiated power purchase agreements?

HECO Companies Response:

There are no differences in the interconnection requirements and cost allocation for the proposed Schedule FIT Tier 1 and Tier 2 Tariff and Agreement from those typically borne by developers in negotiated power purchase agreements.

PUC-IR-327
According to the comments of the Solar Alliance, the proposed change to page 34A-8(d) and 34D-6(a) imposing an additional limitation of 33 percent of the feeder minimum kW load during the period when the proposed generation is available would nullify the effect of increasing the maximum limitation from 10 to 15 percent.

(a) Do you agree with this assessment? Why or why not?

(b) What was the reason for the additional limitation of 33 percent of the feeder maximum?

<u>HECO Companies Response:</u>

The proposed 33 percent of feeder minimum kW load limitation during periods when the proposed generation is available was included to ensure that circuit reliability is not compromised. Without the proposed limitation, there may be situations where a proposed interconnection would negatively impact system reliability, however, because the interconnection meets the "15% of the peak kva load of the feeder" standard, no further study is conducted to evaluate and reveal this circuit condition. For example, a circuit which primarily serves industrial customers tends to have a circuit peak during the day. Under this circumstance, the generation on that circuit could meet the 15% of peak kva load of the feeder standard. However, on a weekend day, while a PV resource (for example) is still generating, the load on that circuit will be much lower resulting in a much higher ratio of generation to load which would have to be studied to insure that interconnection of a resource does not cause reliability concerns. The 33% of feeder minimum kW load would capture this situation and allow an appropriate study to be done that would not be triggered solely by the 15% of peak kva load standard. The modification is derived from an IEEE 1547 (IEEE Standard for Interconnection Distributed Resources with Electric Power Systems) rule that is being used to identify potential problems with the interconnection of distributed generation to an electric power system.

b. Please see the response to part a.

PUC-IR-328
According to the comments of the Solar Alliance, "The proposed change on 34A-2(d) and the change to the Whereas clause on page 34(C)-1, deleting language that would allow an interconnection agreement to be modified to make both the customer and third-party owner or operators of a distributed generation ("DG") system party to an interconnection agreement," would eliminate third-party financing options.

(a) Do you agree with this assessment? Why or why not?
(b) What was the reason for this provision? What are the benefits to the Company or ratepayers of eliminating such financing arrangements; alternatively, what harm does their presence cause?

HECO Companies Response:

(a) The HECO Companies do not agree with this assessment and have no intention to eliminate third party financing options. The changes on Revised Sheet No. 34A-2 and the change to the Whereas clause on Revised Sheet No. 34C-1, which deletes references to a "third-party," is proposed to reflect the addition of a new Appendix II-A entitled "Standard Three Party Interconnection Agreement." See Sheet No. 34C-30.

    The new Appendix II-A provides a Standard Interconnection Agreement for cases where there are three parties – the Hawaiian Electric Company, the owner of the distributed generation system, and the customer of electric service, and would address third-party financing options.

(b) The Standard Three Party Interconnection Agreement used in the new Appendix II-A is the same agreement currently provided upon request for projects with three parties. It is more convenient for the customer and the utility to have both the two-party and three-party agreements in one Appendix (identified as Appendix II and Appendix II-A, respectively). Appendix II-A maintains the same provisions for any third-party financing options as the original Standard Three Party Agreement.

PUC-IR-329
Please describe how the capacity factor-assumptions in the HECO Companies' calculations of Tier 1 and Tier 2 CSP rates consider Hawaii-specific factors and performance. How representative is the data used for CSP systems in Hawaii?

HECO Companies Response:

Please refer to page 11 in the January 21, 2010 filing "HECO Comments on Alternative FIT Tariff" for a narrative discussion of how the HECO Companies derived Hawaii specific capacity factors. Recently, the pricing team has found additional data from the NREL SAM model that supports the solar insolation adjustment from the best solar insolation in the Mojave desert (at Daggett) to Honolulu conditions. The analysis assumes a 25% reduction or 75% of the insolation in Hawaii as compared to Mojave. A NREL CPV report also provided on page 11 of the January 21, 2010 filing "HECO Comments on Alternative FIT Tariff" provides a detailed capacity factor analysis for Los Angeles and Mojave. Los Angeles has a similar insolation profile as Hawaii. In fact, Los Angeles insolation is not as good as Hawaii's, thus the CPV estimate represents a conservative estimate.

PUC-IR-330
Please provide underlying calculations and supporting calculations for all land-purchase or lease-cost assumptions used for the calculation of Tier 1 and Tier 2 rates.

HECO Companies Response:

The land/roof lease cost assumptions are outlined in the project pro formas in Attachment 4 of HECO's "Comments on Alternative FIT Tariff and Standard Agreement."

On-Shore Wind and In-Line Hydro projects used a standard land lease rate of 2 - 4% of revenues on an annual basis.

For CSP, a land lease rate of $10,000/acre/year was used, assuming that dish technology occupies 2 acres/MW and trough technology occupies 6 acres/MW. The comparable lease cost of $10,000/acre/year came from a lease between the Department of Hawaiian Home Lands (DHHL) and private developers. Other private land data was found on the public markets that were similar in cost.

For PV and CPV systems, the projects are assumed to be roof mounted. Because there are as of yet no comparables from Hawaii for these kind of systems, the lease cost assumptions reflect transactions that have occurred on the Mainland where developers have rented roof space to provide power to utilities. A rental figure of $0.10/square foot/year was used, which falls within the range of the roof rental rates observed. The sources of roof rental costs are discussed further on page 7 of HECO's "Schedule FIT Tier 1 and Tier 2 Tariff and Agreement" filed on January 7, 2010. The assumption is that 1 MW of installed capacity fits onto 100,000 square feet of roof space.

PUC-IR-331
Did the HECO Companies' rate calculations include an escalator for land lease costs? If so, describe the size of the escalation. If not, please describe why such an escalation would be inappropriate.

HECO Companies Response:

The HECO Companies did not use an escalator for land lease costs in the rate calculations. It was assumed that a developer would be able to secure a flat-rate lease for a 20-year period. However, including a land lease escalator of 3%, compounded annually, and increasing the rental cost every five years over the course of the 20-year term does not have a significant effect on the resulting tariff (no more than $0.005/kWh).

PUC-IR-332
HECO's proposed Schedule FIT Tier 1 and Tier 2 Tariff and Agreement wind projects would receive 16.1 and 13.8 cents per kWh respectively. Please describe the factors that would make these smaller wind projects more economical, thus featuring a lower rate than the recently signed agreement with the 30-MW First Wind facility, which includes compensation of 17 cents per kWh with an escalator.

HECO Companies Response:

The HECO Companies' proposed Schedule FIT Tier 1 and Tier 2 Tariff and Agreement includes pricing for onshore wind projects that was developed with the adapted Black & Veatch Levelized Cost of Generation (LCOE) model and the methodology presented at the FIT Technical Workshop on November 18, 2009, and subsequent meetings of the parties prior to the filing with the Commission on January 7, 2010. A mid-point of the range of scenario pricing for each FIT Tier was selected. In general, cost assumptions for smaller wind projects reflect simpler projects with a development time of less than one year, lower equipment delivery costs, development, construction, and permitting costs, as compared with relatively larger onshore wind projects.

The 30-MW First Wind (Kahuku Power) facility, as with other Independent Power Producers that sign bilateral contracts (Power Purchase Agreements) with the HECO utilities for large-scale projects, has a negotiated pricing structure. The pricing in the Kahuku Power case reflects the complexities of multi-year development, including design and engineering, permits and approvals, site acquisition and preparation, civil improvements, access road, temporary use of specialized cranes (brought in from the mainland) for erection of 1.5 MW turbines (or similar), any environmental mitigation measures, interconnection with the electric grid, operational requirements, and communications and monitoring.

Smaller projects may also be subject to unique site-specific costs, for example, a FIT Tier 3 wind project located in the same area as the Kahuku Power project could also experience significant permitting, civil work, and line extension costs, in which case it is probable that the energy pricing needed for the project would be significantly higher than the proposed FIT Tier 3 wind rate.

PUC-IR-333
Do owners of Tier 1 projects, such as residential PV solar systems, typically use debt to finance projects? If so, is such debt financing available? If so, under what typical debt rates and terms? If not, what are the typical sources for financing Tier 1 projects?

HECO Companies Response:

There are many ways in which to finance PV systems, including residential PV systems. Some of the options for financing residential systems include taking out a home equity line of credit, taking out a standard bank loan, or financing the project out of pocket. However, for the purposes of setting the PV FIT rates, the HECO Companies assumed that Tier 1 and 2 systems would be financed as commercial installations with a debt and equity component (and a resulting Weighted Average Cost of Capital – WACC) in order to take full advantage of commercial tax benefits for renewable energy and reduce costs to the ratepayers. Because of that, typical solar PV commercial project financing assumptions were used and are relevant for Tier 1 and Tier 2 projects. The financing assumptions were set at 35% debt in the capital structure with a rate of 9% and 65% equity in the capital structure with a rate of 11%. These numbers are in the middle of the range of financing costs that have been observed in the market and result in a Weighted Average Cost of Capital (WACC) of 9.0% after taxes. There are several types of banks that provide loans for commercial projects, but typically local community banks are best suited to lend debt to projects of this size.

PUC-IR-334
Under the HECO Companies' proposed model, would the total cash flow for any of the proposed Tier 1 and Tier 2 rates be negative for a calendar year? Please describe any such instances.

HECO Companies Response:

Yes, generally the annual cash flows become negative after the large renewable energy tax benefits (credits and accelerated depreciation) are used up in the first 6 years. This is partly due to the prescribed fixed price that does not follow annual net cash flow.

PUC-IR-335
Did the HECO Companies assume the same wind speed and thus capacity factor for Tier 1 and Tier 2 wind projects? Would such projects have different elevations such that they would experience different wind speeds? How would the wind speeds differ for Tier 3 projects based on hub height?

HECO Companies Response:

The Hawaiian Electric Companies provided a detailed narrative of the capacity factor assumptions for Tier 1 and Tier 2 wind projects in its "Comments on Alternative FIT Tariff and Standard Agreement" under Docket No. 2008-0273 filed on January 21, 2010. A range of hub heights and wind speeds were considered in developing the range of capacity factors. The analysis developed an initial range using NREL's Mid-Scale Wind Study which provided kWh production profiles for different wind class levels and sizes of turbines and towers (a 10 kW Bergey turbine, a 50 kW EW-15 turbine, and a 100 kW Northern Power turbine). The ranges of kWh production and their associated derived capacity factors were cross checked with manufacturer power curves and wind speed assumptions. The range of wind speeds used to calculate capacity factors from the manufacturer power curves was 12-16 mph. The tower choice, not the turbine size generally determines the access to the higher wind speeds. All of the turbines could be mounted on towers up to 30 meters and some could be mounted on higher towers. The derived capacity factors were within the range provided in the NREL study for Tier 2. However, the Bergey turbine's power curve and detailed excel windcad model produced higher capacity factors to define the high end of the range at 34% for Tier 1. The wind speed for this calculation was 15.5 mph. Please see quoted text below from the January 21, 2010 filing "Comments on Alternative FIT Tariff and Standard Agreement" for more information:

"Capacity factors were derived from NREL's 2008 Mid-Scale Wind Study which provides the kWh of production for different wind class levels and different turbine sizes ("An Analysis of the Technical and Economic Potential for Mid-Scale Wind," Kwartin, Wolfrum, Granfield, Kagel and Appleton, 2008 (http://www.nrel.gov/wind/pdfs/midscale_analysis.pdf)). E3 calculated the capacity factor for class 4 and above which resulted in 18-24% for turbines within Tier 1 and 27%-45% for turbines within Tier 2.

In addition, E3 reviewed manufacturer wind power curves which produced results that were within the range for Tier 2 but extended the range for Tier 1. In particular, the current specifications for a 10kW Bergey defined the high end of the Tier 1 range at 34% capacity factor using the Bergey WindCad model 10 kW Excel-S (Grid-Intertie) and using wind resource assumptions at the high end of the range at 15.5+ mph assuming a 30 meter hub height. The Hawaii specific wind resource map shows a significant amount of wind resource over at 14+ mph. The 30m resource map can be found here: http://www.state.hi.us/dbedt/ert/wwg/windy.html#oahu. The capacity factors used in the analysis included typical losses from shear, blade contamination, turbulence and maintenance."

Wind speed is directly correlated with hub height. Tier 1 and Tier 2 turbines were available on towers between 10m-40m. Tier 3 generally represents much larger turbines between 100kW-5MW in size. Due to other project costs and installation costs (including special cranes for turbine and tower erection), the high end of this range may not be practical. However, even the turbines from 250-1000kW typically have much taller towers. However, the expected tower height range for these turbines is from 40-70m. The Vestas 850kW turbine comes with towers ranging from 44m-74m. Fuhrlander's 600kW turbine comes with either a 50m or 75m tower. Fuhrlander's 250kW turbine comes with either a 42m tower or a 50m tower. Accordingly, the Hawaiian Electric Companies will look at 50m wind resource maps for Tier 3 versus the 30m maps used for Tier 1 and Tier 2 to develop a range of wind speeds.

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